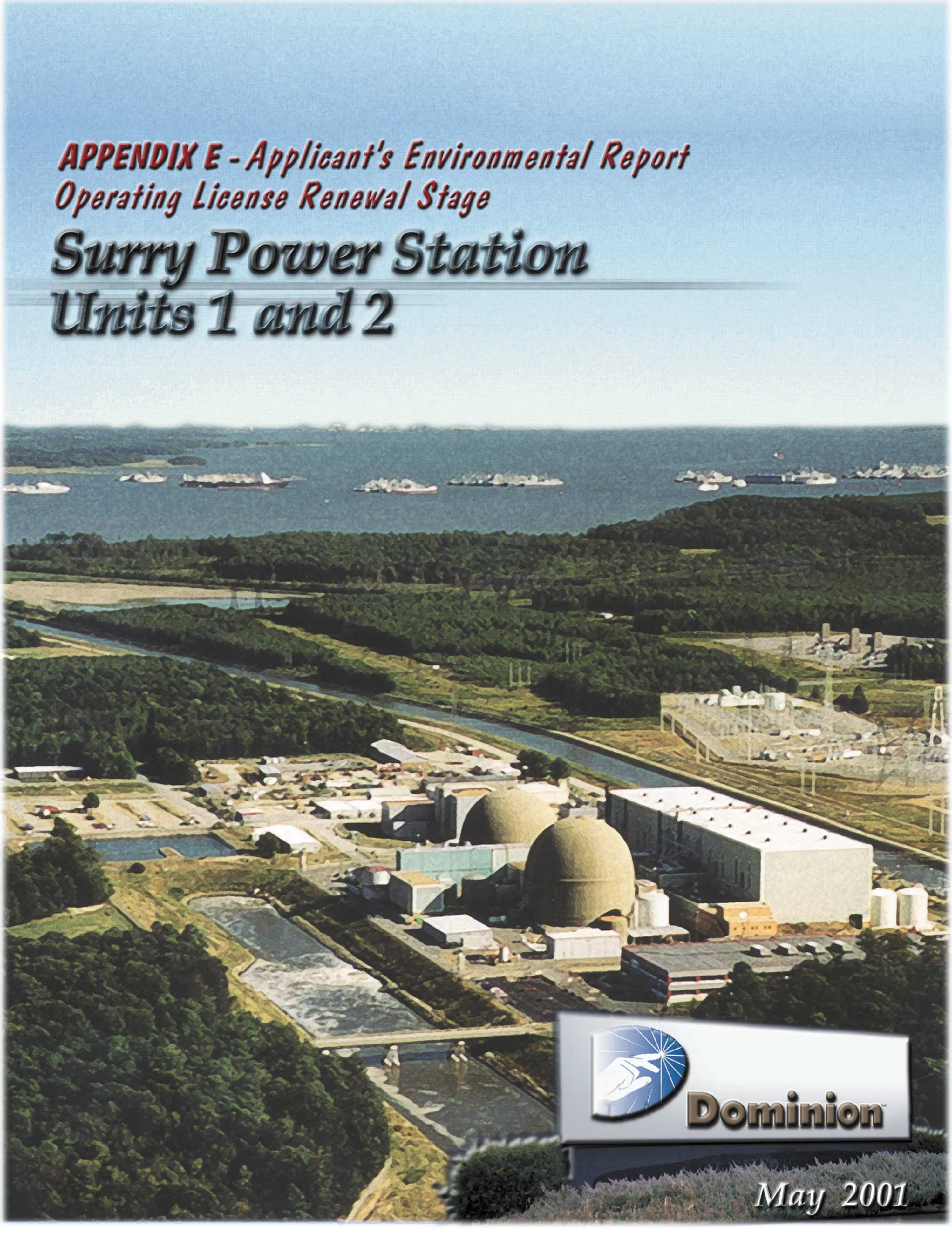
APPENDIX E - Applicant's Environmental Report
Operating License Renewal Stage

Surry Power Station
Units 1 and 2



May 2001

Appendix E

Applicant's Environmental Report –
Operating License Renewal Stage
Surry Power Station Units 1 and 2

Virginia Electric & Power Company
License Nos. DPR-32 and DPR-37

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ACRONYMS AND ABBREVIATIONS

AQCR	Air Quality Control Region
Btu	British thermal unit
CCW	component cooling water
CEQ	Council on Environmental Quality
CFR	Code of Federal Regulations
CWA	Clean Water Act
DSM	demand-side management
EPA	(U.S.) Environmental Protection Agency
ºF	degrees Farenheit
FWS	(U.S.) Fish and Wildlife Service
GEIS	Generic Environmental Impact Statement
gpm	gallons per minute
GWH	gigawatt hours
HIWMA	Hog Island Wildlife Management Area
IPA	integrated plant assessment
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination - External Events
JCSA	James City Service Authority
kV	kilovolt
kWh	kilowatt hour
LOCA	loss of coolant accident
LOS	level of service
MACCS2	Melcor Accident Consequence Code System
msl	mean sea level
MW	megawatt
MWe	megawatt-electric
MWt	megawatt-thermal
NA	Not applicable

NAPS	North Anna Power Station
NEPA	National Environmental Policy Act
NESC®	National Electrical Safety Code®
NMFS	National Marine Fisheries Service
NPDES	National Pollutant Discharge Elimination System
NRC	(U.S.) Nuclear Regulatory Commission
PM	particulate matter
PRA	probabilistic risk assessment
psig	pounds per square inch gage
PWR	pressurized water reactor
RCP	reactor coolant pump
SAMA	Severe Accident Mitigation Alternative
SAMDA	Severe Accident Mitigation Design Alternative
SHPO	State Historic Preservation Officer
SMITTR	surveillance, monitoring, inspection, testing, trending, and recordkeeping
SPS	Surry Power Station Units 1 and 2
SSCs	structures, systems, and components
VDCR	Virginia Department of Conservation and Recreation
VDEQ	Virginia Department of Environmental Quality
VPDES	Virginia Pollutant Discharge Elimination System

1.0 INTRODUCTION

1.1 Purpose and Need for the Proposed Action

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power reactors in accordance with the Atomic Energy Act of 1954 and NRC implementing regulations. Dominion Generation (Dominion) operates Surry Power Station Units 1 and 2 (SPS) pursuant to NRC operating licenses DPR-32 and DPR-37, respectively. The Unit 1 license will expire May 25, 2012, and the Unit 2 license will expire January 29, 2013. Dominion has prepared this environmental report in conjunction with its application to NRC to renew the operating licenses for SPS, as provided by the following NRC regulations:

- Title 10, Energy, Code of Federal Regulations (CFR), Part 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants, Section 54.23, Contents of Application - Environmental Information (10 CFR 54.23) and
- Title 10, Energy, CFR, Part 51, Environmental Protection Requirements for Domestic Licensing and Regulatory Functions, Section 51.53, Post-Construction Environmental Reports, Subsection 51.53(c), Operating License Renewal Stage [10 CFR 51.53(c)]

NRC has defined the purpose and need for the proposed action, the renewal of the operating licenses for nuclear power plants such as SPS, as follows:

> The purpose and need for the proposed action (renewal of an operating license) is to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license to meet future system generating needs, as such needs may be determined by state, utility, and where authorized, federal (other than NRC) decision makers. (Ref. 1.1-1, pp. 28467-28497).

The renewed operating licenses would permit 20 additional years of plant operation, beyond the current SPS licensed operating period of 40 years.

1.2 Environmental Report Scope and Methodology

NRC regulations for domestic licensing of nuclear power plants require an environmental review of applications to renew operating licenses. The NRC regulation 10 CFR 51.53(c) requires that an applicant for license renewal submit with its application a separate document entitled *Applicant's Environmental Report – Operating License Renewal Stage*. In determining what information to include in the SPS Environmental Report, Dominion has relied on NRC regulations and the following supporting documents that provide additional insight into the regulatory requirements.

- NRC supplementary information in the *Federal Register* (Refs. 1.1-1; pp. 28467 - 28497; 1.2-1, pp. 39555 - 39556; 1.2-2, pp. 66537 - 66554; and 1.2-3, pp. 48496 - 48507)
- *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (Refs. 1.2-4 and 1.2-5)
- *Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses* (Ref. 1.2-6)
- *Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response* (Ref. 1.2-7)

Dominion has prepared Table 1-1 to verify conformance with regulatory requirements. Table 1-1 indicates each section in which the environmental report responds to each requirement of 10 CFR 51.53(c). In addition, each responsive section in the report is prefaced by a boxed quote of the regulatory language and applicable supporting document language.

The environmental report comprises nine chapters. This chapter describes the purpose and need for the proposed action, renewal of SPS operating licenses. Chapter 2 describes the environs affected by SPS operations and Chapter 3 describes pertinent aspects of the plant and its associated infrastructure. Chapter 4 provides results of the analyses of impacts on the environment from SPS license renewal. Chapter 5 describes the process Dominion used to identify any new and significant information regarding environmental impacts. Chapter 6 summarizes the impacts of license renewal and mitigating actions. Chapter 7 describes feasible alternatives to the proposed action and their environmental impacts. Chapter 8 compares the impacts of license renewal with those alternatives. Chapter 9 discusses SPS compliance with regulatory requirements.

Table 1-1
Environmental Report Responses to License Renewal Environmental Regulatory Requirements

Regulatory Requirement	Responsive Environmental Report Section(s)
10 CFR 51.53(c)(1)	Entire Document
10 CFR 51.53(c)(2), Sentences 1 and 2	3.0 Proposed Action
10 CFR 51.53(c)(2), Sentence 3	7.2.2 Environmental Impacts of Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(1)	4.0 Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	6.3 Unavoidable Adverse Impacts
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	7.0 Alternatives to the Proposed Action 8.0 Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	6.5 Short-term Use Versus Long-term Productivity of the Environment
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	6.4 Irreversible and Irretrievable Resource Commitments
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	4.0 Environmental Consequences of the Proposed Action and Mitigating Actions 6.2 Mitigation 7.2.2 Environmental Impacts of Alternatives 8.0 Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	9.0 Status of Compliance
10 CFR 51.53(c)(2) and 10 CFR 51.45(e)	4.0 Environmental Consequences of the Proposed Action and Mitigating Actions 6.3 Unavoidable Adverse Impacts
10 CFR 51.53(c)(3)(ii)(A)	4.1 Water Use Conflicts (Plants with Cooling Ponds or Cooling Towers Using Make-Up Water from a Small River with Low Flow) 4.6 Groundwater Use Conflicts (Plants Using Cooling Towers Withdrawing Make-Up Water from a Small River)

Table 1-1 (continued)
Environmental Report Responses to License Renewal Environmental Regulatory Requirements

Regulatory Requirement	Responsive Environmental Report Section(s)
10 CFR 51.53(c)(3)(ii)(B)	4.2 Entrainment of Fish and Shellfish in Early Life Stages 4.3 Impingement of Fish and Shellfish 4.4 Heat Shock
10 CFR 51.53(c)(3)(ii)(C)	4.5 Groundwater Use Conflicts (Plants Using > 100 gpm of Groundwater) 4.7 Groundwater Use Conflicts (Plants Using Ranney Wells)
10 CFR 51.53(c)(3)(ii)(D)	4.8 Degradation of Groundwater Quality
10 CFR 51.53(c)(3)(ii)(E)	4.9 Impacts of Refurbishment on Terrestrial Resources 4.10 Threatened or Endangered Species
10 CFR 51.53(c)(3)(ii)(F)	4.11 Air Quality During Refurbishment (Non-Attainment or Maintenance Areas)
10 CFR 51.53(c)(3)(ii)(G)	4.12 Impact of Microbiological Organisms on Public Health
10 CFR 51.53(c)(3)(ii)(H)	4.13 Electric Shock from Transmission-Line-Induced Currents
10 CFR 51.53(c)(3)(ii)(I)	4.14 Housing Impacts 4.15 Public Utilities: Public Water Supply Availability 4.16 Education Impacts from Refurbishment 4.17 Offsite Land Use
10 CFR 51.53(c)(3)(ii)(J)	4.18 Transportation
10 CFR 51.53(c)(3)(ii)(K)	4.19 Historic and Archaeological Resources
10 CFR 51.53(c)(3)(ii)(L)	4.20 Severe Accident Mitigation Alternatives
10 CFR 51.53(c)(3)(iii)	4.0 Environmental Consequences of the Proposed Action and Mitigating Actions 6.2 Mitigation
10 CFR 51.53(c)(3)(iv)	5.0 Assessment of New and Significant Information
10 CFR 51, Appendix B, Table B-1, Footnote 6	2.11 Minority and Low-income Populations

1.3 References

Ref. 1.1-1 U.S. Nuclear Regulatory Commission. 1996. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." *Federal Register*. 61, No. 109. June 5.

Ref. 1.2-1 U.S. Nuclear Regulatory Commission. 1996. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Correction." *Federal Register*. 61, No. 147. July 30.

Ref. 1.2-2 U.S. Nuclear Regulatory Commission. 1996. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." *Federal Register*. 61, No. 244. December 18.

Ref. 1.2-3 U.S. Nuclear Regulatory Commission. 1999. "Changes to Requirements for Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Final Rules." *Federal Register*. 64, No. 171. September 3.

Ref. 1.2-4 U.S. Nuclear Regulatory Commission. 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS). Volumes 1 and 2. NUREG-1437. Washington, DC.

Ref. 1.2-5 U.S. Nuclear Regulatory Commission. 1999. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS); Section 6.3, "Transportation", and Table 9-1, "Summary of findings on NEPA issues for license renewal of nuclear power plants." NUREG-1437. Volume 1, Addendum 1. Washington, DC.

Ref. 1.2-6 U.S. Nuclear Regulatory Commission. 1996. *Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses*. NUREG-1440. Washington, DC.

Ref. 1.2-7 U.S. Nuclear Regulatory Commission. 1996. *Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents*: *Review of Concerns and NRC Staff Response*. Volumes 1 and 2. NUREG-1529. Washington, DC.

2.0 SITE AND ENVIRONMENTAL INTERFACES

2.1 Location and Features

Surry Power Station (SPS) is located in Surry County, Virginia, on the south side of the James River, approximately 25 miles upstream of the point where the river enters the Chesapeake Bay (Figure 2-1). This location is latitude 37° 9' 58" North and longitude 76° 41' 55" West for Unit 1 and latitude 37° 9' 57" North and longitude 76° 41' 53" West for Unit 2. The SPS site consists of approximately 840 acres on Gravel Neck Peninsula. In addition to the two nuclear reactors and their turbine building, intake and discharge canals, and auxiliary buildings; the 840-acre site is the location of the Gravel Neck Combustion Turbines Station, a switchyard, and an Independent Spent Fuel Storage Installation (Figure 2-2).

Gravel Neck Peninsula is at the upstream limit of saltwater incursion to the James River; upstream of Gravel Neck is tidal river and downstream is an estuary. The 840-acre site extends as a band across the peninsula. Steep bluffs drop to the river on either side and to the tip of the peninsula, which is low and marshy. Hog Island Wildlife Management Area (HIWMA), a Commonwealth wildlife management area, is located on the tip of the peninsula (Figure 2-3).

Hog Island Wildlife Management Area.

The site is 7 miles south of Colonial Williamsburg and 8 miles east-northeast of the town of Surry. Jamestown Island, part of the Colonial National Historic Park, is to the northwest on the northern shore of the James River. The area within 10 miles of the site includes Surry, Isle of Wight, York, and James City Counties, and parts of the cities of Newport News and Williamsburg. The counties surrounding SPS are predominantly rural, characterized by farmland, woods, and marshy wetlands. East and south of the site, at distances between 10 and 30 miles, are the urban areas of Hampton, Newport News, Norfolk, and Portsmouth, Virginia (Ref. 2.1-1, Section 2.1.1.1) and others, collectively known as Hampton Roads.

Section 3.1 describes key features of SPS, and Section 3.5 describes the Gravel Neck Combustion Turbines Station.

2.2 Aquatic and Riparian Ecological Communities

The James River rises in the Allegheny Mountains near the Virginia/West Virginia border and flows in a southeasterly direction to Hampton Roads (that area of Virginia that includes Newport News, Norfolk, Portsmouth, Hampton, and surrounding cities and towns), where it enters the Chesapeake Bay. The James River flows 430 miles from its headwaters (the confluence of the Cowpasture and Jackson Rivers) to the Chesapeake Bay, crossing portions of four physiographic regions: Blue Ridge, Valley and Ridge, Piedmont, and Coastal Plain. The river drains 10,000 square miles, just over 25 percent of the total land area of Virginia. Overall, about 71 percent of the basin is forested, 23 percent is agricultural and 6 percent is urban (Refs. 2.2-1 and 2.2-2, pg. 4). The lower James River flows through the Coastal Plain of Virginia, which is virtually flat in tidewater areas, generally ranging from 0 to 100 feet above mean sea level.

Two major tributaries enter the river between Richmond and Hampton Roads. The Appomattox River enters the James River from the south, in the stretch of river between Richmond and Petersburg. The Chickahominy River enters from the north, just west of Williamsburg. Although the James River downstream of Richmond was severely polluted for many years, the passage of the Clean Water Act in 1972 and implementation of associated regulations, such as the National Pollutant Discharge Elimination System, has reduced the flow of (toxic) point-source pollutants into the James River ecosystem (Ref. 2.2-3). Pollution prevention measures and programs carried out by industrial entities in the area have further reduced chemical discharges to the James. At present, nutrients from sewage treatment facilities, agricultural operations, and urban runoff and bacteria from combined sewer systems (those that combine storm water and sewage) are considered the chief threats to the water quality of the lower James River (Ref. 2.2-1).

In the vicinity of SPS, the James River is approximately 2.5 miles wide. Cobham Bay lies west (just upstream) of the Gravel Neck Peninsula and represents the approximate limit of saltwater incursion, effectively dividing the James River into a tidally-influenced freshwater river upstream (to the Fall Line at Richmond) and an estuary downstream. The U.S. Army Corps of Engineers historically has dredged the main channel of the lower James River so that ocean-going vessels can proceed upriver as far as Hopewell, approximately 50 river-miles above SPS.

The flow of the James River in the area of SPS is complex, composed of three basic components. In decreasing order of volume, these flows include (1) the back-and-forth flow of tides, (2) the upstream flow of highly saline water near the bottom of the river and downstream flow of less-saline water at the surface, and (3) the outflow of freshwater from the James River watershed. The limit of saltwater incursion may shift several miles upstream during periods of low river flow and downstream during periods of high river flow (Ref. 2.2-4, pg. 15).

Salinities ranging from 0.0 to 12.2 parts per thousand have been observed in the James River off the tip of Hog Point (Ref. 2.2-5, pg. 29). Salinities in the area of the SPS intakes (downstream of Hog Point) are typically higher, up to 17.0 parts per thousand, while those in the area of the SPS discharge canal (upstream of Hog Point) are typically lower at 0.0 to 9.2 parts per thousand.

Freshwater flows in the vicinity of SPS ranged from 857 to 39,778 cubic feet per second over the 1934-1965 period, with a mean value of 9,952 cubic feet per second (Refs. 2.2-7, pg. 14, and 2.2-4, pg. 14). By comparison, the total tidal flow in the area of SPS (upriver with flood tides and downriver with ebb tides) is about 130,000 cubic feet per second or more (Ref. 2.2-5, pg. 20). Even under flood conditions, most of the flow in the James River at SPS is associated with tidal movement rather than freshwater inflow from the watershed. Generally, high river flows occur in winter months while low flows occur in late summer and fall.

The lower James River supports a diverse assemblage of finfish species, ranging from exclusively marine species near the Chesapeake Bay to exclusively freshwater species at the Fall Line in Richmond. Approximately 80 fish species are known from the brackish portion of the James River downstream of SPS, with another 40 or so species recorded from the tidally influenced (freshwater) portion of the river upstream of SPS (Ref. 2.2-5, pg. 34). Distributions and abundances of particular species vary between seasons and years, depending on salinity differences and natural fluctuations in fish populations.

Dominion conducted extensive surveys of James River aquatic biota in the 1970s. While preparing this environmental report, Dominion contacted Virginia Institute of Marine Sciences for more recent information. The following paragraphs describe the historic Dominion data and the more recent data collected by the Virginia Institute of Marine Sciences.

Dominion collected 63 fish species in monthly haul seine surveys conducted from 1970-1978 that were intended to characterize fish populations of the shore zone in the vicinity of SPS (Ref. 2.2-4, pg. 54). Five species made up more than 75 percent of fish collected. These were the Atlantic menhaden (*Brevoortia tyrannus*), blueback herring (*Alosa aestivalis*), inland silverside (*Menidia beryllina*), bay anchovy (*Anchoa mitchilli*), and spottail shiner (*Notropis hudsonius*). [Note that the Cooling Water Intake Studies (Ref. 2.2-4) gives the common name of *M. beryllina* as the tidewater silverside, based on American Fisheries Society nomenclature accepted at that time. *M. beryllina* is now commonly called the inland silverside. The fish now commonly known as the tidewater silverside (*M. peninsulae*) is restricted to Florida and the Gulf States.] Over the same period, 42 fish species were collected in otter trawl samples that were intended to characterize fish populations in deeper waters (the "shelf zone") adjacent to the main river channel (Ref. 2.2-4, pg. 60). Five species comprised more than 80 percent of fish collected in trawl samples. These species were the hogchoker (*Trinectes maculatus*), spot (*Leiostomus xanthurus*), channel catfish (*Ictalurus punctatus*), Atlantic croaker (*Micropogonias undulatus*), and bay anchovy.

Between 1996 and 2000 Virginia Institute of Marine Sciences conducted approximately 350 deep water ichthyoplankton trawl surveys in the James River in the vicinity of Hog Island. In those collections, four species comprised more than 80 percent of the catch: hogchoker, white perch (*Morone americana*), Atlantic croaker, and bay anchovy. Spot was the fifth most abundant species (Ref. 2.2-6). Salinity appears to be the most important factor influencing the relative abundances of fishes between the two sampling periods.

In addition to finfish, a number of invertebrate aquatic species were found in the vicinity of SPS. These include zooplankton (dominated by copepods), amphipods (notably the scud, *Gammarus*), and a variety of benthic organisms (e.g., polychaetes and shellfish) (Refs. 2.2-5, VI[B][D] and 2.2-6, II[E][2]). Shellfish formed the bulk of the benthic biomass from the transition zone in the vicinity of SPS to the Chesapeake Bay. The brackish water clam, *Rangia cuneata*, a species capable of tolerating a wide range of salinities, dominated the benthic community in the vicinity of SPS (Refs. 2.2-5, VI[B][D] and 2.2-7, II[E][2]). Larval American oysters (*Crassostrea virginica*) occurred in the area as meroplankton, but adults were uncommon. The more recent trawl survey collected oysters, blue crabs, spider crabs, eight species of shrimp and five species of clams (Ref. 2.2-6). The diversity of macroinvertebrate benthic fauna is usually low in a transition zone, increasing downstream to seawater and upstream (moderately) to freshwater. A combination of physical, chemical, and biological factors influence the distribution of benthic organisms, but, as with the finfish, salinity appears to exert the greatest influence.

2.3 Groundwater Resources

The SPS site lies within the Coastal Plain Physiographic Province and is underlain by approximately 1,300 feet of relatively unconsolidated Cretaceous to Holocene sand, silty sand, gravel, marl, and clay. These strata overlay crystalline basement rock of pre-Cretaceous age and dip and thicken to the southeast (Ref. 2.1-1, Section 2.4.2). The site lies in a region characterized by estuaries in a drowned coastline resulting from sediment load and a post-glacial rise of sea level (Ref. 2.3-1, pg. 2.5-1). There was no evidence of faulting during the exploratory drilling and construction of the facility. All available information indicates that the crystalline basement beneath the site has been tectonically dormant since the Cretaceous period (Ref. 2.1-1, pg. 2.4-3). The formations of interest at the site, due to their water-bearing characteristics, consist of the Shirley formation; the Yorktown, the St. Marys, and the Calvert formations of the Chesapeake Group and the Chickahominy formation; the Nanjemony formation; the Aquia formation; and the Potomac formation (Ref. 2.1-1, Section 2.4). These formations and the aquifers that comprise them are described in Table 2-1.

The Eocene and Cretaceous formations encountered at a depth of approximately 290 to 320 feet below land surface are comprised of a series of confining units and aquifers. The aquifers of interest within these units are the Aquia aquifer and the upper, middle, and lower Potomac aquifers. The sands of these units are excellent aquifers and supply many domestic and some industrial wells in the area (Ref. 2.1-1, pg. 2.3-1).

Wells installed in these formations are under confined (artesian) conditions and generally yield from 75 to 200 gallons per minute (gpm), although larger production wells can produce higher yields. For example, a 799-foot-deep well approximately 5 miles south of the site yielded 940 gpm with only 20.25 feet of drawdown (Ref. 2.1-1, pg. 2.3-9). Recharge to the confined aquifers occurs through infiltration to the sediment in outcrop locations along the Fall Line west of the site (Ref. 2.3-1, pg. 2.5-15). In general, the quality of water resources from the deep aquifers is good, except near the coast or where potentiometric levels have dropped significantly below mean sea level. In these areas, saltwater intrusion does occur.

The closest offsite wells installed within the deep aquifers are located approximately 1 mile north of the site on the Hog Island Tract of HIWMA, and at Drewry Point, approximately 0.6 mile to the southwest (Figure 2-2). These wells, based on their depths, appear to be installed within the Aquia aquifer and are therefore isolated by the upper Potomac confining unit from the upper Potomac aquifer pumped by the SPS wells. The Drewry Point well supplies domestic water to a vacation cottage. Both wells are approximately 340 feet deep and yield about 35 gpm. The hydraulic gradient of the deep aquifers is generally toward the east in the direction of thickening deposition (Ref. 2.3-3, pg. 2).

Due to the isolation of the site by the James River to the north, east, and west and the wildlife management area to the south, no substantial industrial or residential development is likely to occur in the immediate vicinity of the SPS site. Therefore, no additional demand of a substantial nature is expected locally upon the groundwater supply.

2.4 Critical and Important Terrestrial Habitats

Most of the SPS site consists of generation and maintenance facilities, laydown areas, parking lots, roads, and mowed grass. The only terrestrial community at the site consists of remnants of mixed pine-hardwood forests that were used for timber production prior to acquisition by Dominion. Wildlife species found in the forested portions of SPS are those typically found in upland forests of Coastal Virginia.

The Hog Island Tract of the HIWMA is adjacent to the northern boundary of SPS at the tip of Gravel Neck Peninsula. The 2,900 acres of the Hog Island Tract are primarily tidal marshes and diked impoundments that are interspersed with pine forests. The Carlisle and Stewart Tracts of the HIWMA, approximately 1,000 acres in extent, are southeast of SPS. These parcels are primarily upland forested areas, but also contain tidal marshes along Lawnes Creek. All three tracts of the HIWMA are owned by the U.S. Department of Game and Inland Fisheries and support a rich variety of wildlife. The tidal flats and marshes provide habitat for large numbers and numerous species of migratory shore birds, wading birds, and waterfowl. In addition, the Hog Island Tract provides habitat for numerous amphibians, reptiles, mammals, and upland game birds. Figure 2-3 shows the location of these tracts.

Physical features (e.g., length, width, route) of each of the transmission line systems associated with SPS are described in Section 3.1.3. The transmission corridors are situated within the Coastal Plain physiographic province. Flat to gently rolling terrain characterizes this region. Transmission lines that originate at SPS traverse land-use categories typical of Coastal Virginia, such as row crops, pasture, pine plantations, and abandoned (old) fields. In addition, the transmission corridors pass through more natural habitat types, such as pine-hardwood forests, bottomland hardwood forests, and shrub bogs. The Suffolk-to-Yadkin transmission corridor traverses a 2-mile portion of the Great Dismal Swamp National Wildlife Refuge, where the habitat surrounding the transmission corridor is hardwood swamp. The Chuckatuck-to-Whealton corridor crosses a 1,000-foot portion of the Ragged Island Wildlife Management Area, a 1,537 acre tract along the lower James River that consists of brackish marsh and low, pine-covered islands (Ref. 2.4-1, pp. 1 and 2). The Great Dismal Swamp National Wildlife Refuge and the Ragged Island Wildlife Management Area support a variety of reptiles, amphibians, mammals, and birds.

No areas designated by the U.S. Fish and Wildlife Service as "critical habitat" for endangered species exist at SPS or adjacent to associated transmission lines. With the exception of the Great Dismal Swamp National Wildlife Refuge and two state wildlife management areas (HIWMA and Ragged Island Wildlife Management Area), the transmission corridors do not cross any state or federal parks or wildlife management areas.

Except in unusual circumstances, transmission corridors are maintained on a three-year cycle. Mechanical mowing and selective herbicide application are the predominate methods for corridor maintenance. In areas where mowing is impractical or undesirable (e.g., wetlands and densely vegetated areas), handcutting and/or non-restricted-use herbicides are used. Selective handcutting is sometimes used in sensitive areas such as wetlands. For example, herbicides are not used on the corridor within the Great Dismal Swamp National Wildlife Refuge or in the Ragged Island Wildlife Management Area. Instead, trees are controlled by selective handcutting. Locations of rare or sensitive plant species are marked on the cutting sketches (Ref. 2.4-2) that Dominion maintains for all its transmission lines. These cutting sketches, along with specifications regarding herbicide use and brush control, are provided to corridor maintenance contractors so that adverse impacts on rare and sensitive species and habitats can be avoided.

Dominion allows landowners, hunting clubs, and conservation organizations to establish wildlife food plots or Christmas tree plantations under transmission lines. Dominion supports these efforts through cost sharing.

2.5 Threatened or Endangered Species

Animal and plant species that are federally or state-listed as endangered or threatened and that occur or could occur (based on habitat and known geographic range) in the vicinity of SPS or along associated transmission lines are listed in Table 2-2.

There is an inactive bald eagle (*Haliaeetus leucocephalus*) nest near the Independent Spent Fuel Storage Installation at SPS. The nest was active for several years, but has not been used recently. The pair of eagles associated with this nest has apparently constructed a nest at the HIWMA, approximately ½ mile from SPS. This nest has successfully produced fledgling eagles for the past 4 years. Although it has not been proven that the eagles associated with this nest are the same pair that formerly nested at SPS, it seems to be a reasonable assumption because the nest at SPS became inactive at the same time that the Hog Island nest was constructed.

The barking treefrog (*Hyla gratiosa*), state-listed as threatened, is known from Surry County, but has not been found on Dominion property. This frog inhabits low, wet, wooded areas.

With the exception of the barking treefrog and the bald eagle, terrestrial species that are federally and/or state-listed as endangered or threatened are not known to exist at SPS or along the transmission lines. The species included in Table 2-2 were taken primarily from lists of species recorded by the Virginia Department of Conservation and Recreation's (VDCR's) Natural Heritage Program as occurring in the counties traversed by the transmission lines (Ref. 2.5-1). Species with no recorded county occurrences were included in Table 2-2 if they could occur in the vicinity of SPS or along associated transmission lines, based on habitat and known geographic range.

Some of the bird species in Table 2-2 would occur in eastern Virginia only during peak migration or seasonally (winter or summer). For example, migrant and wintering peregrine falcons (*Falco peregrinus*) are occasionally observed in Coastal Virginia and have been observed in the City of Newport News (Ref. 2.5-1, City of Newport News). Typical winter habitats for the peregrine falcon include coastal shorelines, lake and river margins, coastal ponds, sloughs, and marshes. Thus, peregrine falcons could occur at SPS or along the transmission lines during migration.

The transmission corridors are managed to prevent woody growth from reaching the transmission lines. The removal of woody species can provide outstanding grassland and bog-like habitat for many rare plant species dependent on open conditions. Dominion cooperates with VDCR's Natural Heritage Program (see, for example, Ref. 2.5-2). Although several rare plant species have been located along various Dominion transmission corridors, no endangered or threatened plants have been recorded at SPS or along the transmission corridors associated with SPS.

Dominion and its contractors conducted extensive surveys of fish and aquatic invertebrates in the lower James River in the vicinity of SPS in the 1970s in support of Clean Water Act Section 316(a) and (b) Demonstrations, but have not systematically surveyed these aquatic resources in recent years. Based on these historical surveys and a review of the scientific literature, no Federally-listed aquatic species is found in the lower James River. Burkhead and Jenkins in *Virginia's Endangered Species* (Ref. 2.5-3, Table 28) list only one threatened or endangered fish species in the entire James River drainage, the orangefin madtom (*Noturus gilberti*), which occurs in the headwaters of the James, several hundred miles upstream of SPS.

The Atlantic sturgeon (*Acipenser oxyrhynchus*), a candidate for Federal listing, was reported in the vicinity of SPS in the early 1970s (Ref. 2.2-7, Appendix G) and was subsequently collected in research and monitoring studies conducted by Dominion and Dominion-funded entities in the mid-to late 1970s (Ref. 2.2-4, Table 30). A number of authorities on the fishes of Virginia and the mid-Atlantic coast also list this species as occurring in the lower reaches of the James River (Ref. 2.5-4, pg. 41, and 2.5-5, pg. 187).

The blackbanded sunfish (*Enneacanthus chaetodon*), listed as endangered by the Commonwealth of Virginia, is reported to occur in Prince George, Surry, and Sussex Counties west of SPS (Refs. 2.5-5, pg. 723, and 2.5-6). Prince George and Surry Counties are crossed by the SPS-to-Hopewell transmission line corridor (see Section 3.1.3). This species, is typically found in heavily vegetated ponds, swamps, and streams in the Atlantic Coastal Plain and is not believed to occur in the James River drainage (Refs. 2.5-4, pg. 587, and 2.5-5, pg. 723). All known populations of blackbanded sunfish in Virginia are in the Chowan River drainage, which includes the Blackwater, Nottoway, and Meherrin River systems that rise in the Central Piedmont of Virginia and empty into Albemarle Sound, North Carolina. It is possible that an undiscovered population of blackbanded sunfish may be present in a stream or wetland crossed by the SPS-to-Hopewell transmission line corridor in Prince George or Surry County; however, based on the known distribution of this species, it appears to be unlikely.

Although not recorded in Virginia for more than 100 years, the shortnose sturgeon (*Acipenser brevirostrum*) is on the state's list of rare animal species. This listing is based on the fact that the species occurs in major river systems north and south of the Chesapeake Bay, is presumed to have spawned in the four major estuarine drainages of the Chesapeake Bay (including the James River) in Virginia as late as the 19th century, and may reappear in the future if restoration efforts are successful. At present, the shortnose sturgeon is listed as Endangered by the National Marine Fisheries Service and Endangered by the Commonwealth of Virginia. It also appears on the VDCR list of "Extinct and Extirpated Animals of Virginia."

2.6 Regional Demography

The *Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants* (GEIS) presents a population characterization method that is based on two factors: "sparseness" and "proximity" (Ref. 2.6-1, Section C.1.4). "Sparseness" measures population density and city size within 20 miles of a site and categorizes the demographic information as follows:

Demographic Categories Based on Sparseness

Category		
Most sparse	1.	Less than 40 persons per square mile and no community with 25,000 or more persons within 20 miles
	2.	40 to 60 persons per square mile and no community with 25,000 or more persons within 20 miles
	3.	60 to 120 persons per square mile or less than 60 persons per square mile with at least one community with 25,000 or more persons within 20 miles
Least sparse	4.	Greater than or equal to 120 persons per square mile within 20 miles

Source: Ref. 2.6-1, pg. C-159.

"Proximity" measures population density and city size within 50 miles and categorizes the demographic information as follows:

Demographic Categories Based on Proximity

Category		
Not in close proximity	1.	No city with 100,000 or more persons and less than 50 persons per square mile within 50 miles
	2.	No city with 100,000 or more persons and between 50 and 190 persons per square mile within 50 miles
	3.	One or more cities with 100,000 or more persons and less than 190 persons per square mile within 50 miles
In close proximity	4.	Greater than or equal to 190 persons per square mile within 50 miles

Source: Ref. 2.6-1, pg. C-159.

The GEIS then uses the following matrix to rank the population category as low, medium, or high:

GEIS Sparseness and Proximity Matrix

Sparseness \ Proximity	1	2	3	4
1	1.1	1.2	1.3	1.4
2	2.1	2.2	2.3	2.4
3	3.1	3.2	3.3	3.4
4	4.1	4.2	4.3	4.4

Low Population Area

Medium Population Area

High Population Area

Source: Ref. 2.6-1, pg. C-6.

Dominion used 1990 census data from the U.S. Census Bureau website (Ref. 2.6-2) and geographic information system software (ArcView®) to determine demographic characteristics in the SPS vicinity. The Census Bureau provides updated annual projections, in addition to decennial data, for selected portions of its demographic information. However, Section 2.11 (Minority and Low-Income Populations) of this environmental report uses 1990 minority and low-income population demographic information, because updated projections are not available by census tract. Dominion chose to also use 1990 data in this section, so the data sets are consistent throughout the SPS environmental report.

As derived from Census Bureau information, 369,852 people live within 20 miles of SPS. Applying the GEIS sparseness measures, SPS has a population density of 294 persons per square mile within 20 miles and falls into the "least sparse" category, Category 4 (having greater than or equal to 120 persons per square mile within 20 miles).

As estimated from Census Bureau information, 1,892,210 people live within 50 miles of SPS. This equates to a population density of 241 persons per square mile within 50 miles. Applying the GEIS proximity measures, SPS is classified as being "in close proximity," Category 4 (having greater than or equal to 190 persons per square mile within 50 miles). According to the GEIS sparseness and proximity matrix, the SPS ranks of sparseness

Category 4 and proximity Category 4 result in the conclusion that SPS is located in a high population area.

All or parts of 31 counties (Figure 2-5) and 14 cities are located within 50 miles of SPS. Of the counties, 25 are in Virginia and 6 are in North Carolina. Approximately 60 percent of SPS's employees live in four areas: Isle of Wight, James City (James City County is one of several Virginia metropolitan areas that is both a city and a county), and Surry Counties and the City of Newport News. The remaining 40 percent is distributed across 28 counties and 13 cities, with numbers ranging from 1 to 61 people.

The Hampton Roads region, which includes Isle of Wight County, James City County, and the City of Newport News, is a metropolitan area with a current population exceeding 1.5 million and that is growing at the moderate rate of 1 percent a year (Ref. 2.6-3). Surry County is rural. Statewide, population growth is higher in Virginia's counties than in its cities, showing an overall trend of suburbanization. This trend is evident in the potentially affected communities. The City of Newport News shows a negative net immigration rate over the last decade and Isle of Wight, James City, and Surry Counties all have positive net immigration rates (Ref. 2.6-4).

Table 2-3 shows estimated populations and annual growth rates for the four communities with the greatest potential to be socioeconomically affected by license renewal activities. Figures 2-3 and 2-5 show the locations of these areas.

2.7 Economic Base

Hampton Roads has experienced steady growth in population and economic activity during the last decade, as has Surry County to a lesser extent. The Hampton Roads area is the 27th largest metropolitan statistical area in the United States with more than 1.5 million people. It has a transportation network of trucking and railroad terminals, interstate highway access to main east-west and north-south routes, international airports, and an international deepwater, ice-free seaport, giving the area access to both domestic and international markets (Ref. 2.7-1). Historically, there was a heavy reliance in Hampton Roads on defense-related industry, particularly shipbuilding. In recent years, the regional economy has become more diversified with major business, financial, and health care components, as well as a growing high-tech sector. Regionally, services is now the largest employment sector (Ref. 2.6-3).

The unemployment rate for the Commonwealth of Virginia for 1998 was 2.9 percent. In comparison, Isle of Wight, James City, and Surry Counties and the City of Newport News had 1998 unemployment rates of 3.2, 2.1, 8.0, and 4.1 percent, respectively (Ref. 2.7-2).

2.8 Taxes

SPS pays annual property taxes to Surry County. Taxes fund Surry County operations, including the school system and road maintenance. For the years 1995 to 1998, SPS's property taxes provided about 76 percent of Surry County's total property tax revenue. Property taxes cover about 66 percent of Surry County's total operating budget. If the operating licenses for SPS were not renewed and the plant was decommissioned, impacts to the tax base of the surrounding communities and their economic structures could be significant, as discussed in Section 8.4.7 of the GEIS (Ref. 2.6-1).

Dominion projects that SPS's annual property taxes will remain constant at about $10 million through the license renewal period (Ref. 2.8-1). The potential effects of deregulation are not yet fully known. Any changes to SPS tax rates due to deregulation, however, would be independent of license renewal. Table 2-4 compares SPS's tax payments to Surry County tax revenues.

2.9 Land Use Planning

This section focuses on Isle of Wight County, James City County, the City of Newport News, and Surry County because approximately 60 percent of the permanent SPS workforce lives in these communities (Section 3.4) and Dominion pays property taxes in Surry County.

The Commonwealth of Virginia mandates that cities and counties have comprehensive land use plans. In the four communities with the greatest potential to be affected, such plans are in place. Isle of Wight County (Ref. 2.9-1), James City County (Ref. 2.9-2), and the City of Newport News (Ref. 2.9-3) have all experienced significant growth in the last decade and their comprehensive plans reflect planning efforts and public involvement in the planning process undertaken during the 1990s. Surry County's plan was written in the 1970s (Ref. 2.9-4).

Land use planning tools, such as zoning, guide future growth and development. All plans share the goals of encouraging growth and development in areas where public facilities, such as water and sewer systems, are planned and discouraging strip development along county roads and highways. All three counties, Isle of Wight, James City, and Surry, identified in their comprehensive land use plans the goal of preserving and protecting rural land uses for agriculture and forestry. The City of Newport News identified neighborhoods as the City's building blocks and emphasized protection of residential neighborhoods from incompatible infill development and commercial or industrial intrusions.

During the 30 years since SPS was constructed, Surry County has experienced little growth. County population declined by 6 percent during the 1960s and grew only 2 percent during the 1970s, 3 percent during the 1980s, and an estimated 7 percent during the 1990s. The County's economic base continues to be agricultural production, with peanuts, soybeans, and corn as the primary crops. As the number of farms has decreased, average farm size has increased from 146 acres in 1959 to 245 acres in 1996 (Ref. 2.9-4, pg. 8). This change is due primarily to mechanization and improved farming methods (Ref. 2.9-5). With the County encompassing 179,200 acres, the dominant land use remains commercial forest with approximately 133,948 acres in production (Ref. 2.9-5), up from 101,367 acres in 1970 (Ref. 2.9-4, pg. 20). The dominant forest types on these acres are loblolly-shortleaf pine, oak-pine, oak-hickory, and oak-gum-cypress. Ninety-nine percent of the forested lands are privately owned (Ref. 2.9-5).

2.10 Social Services and Public Facilities

2.10.1 Public Water Supply

SPS gets potable water from a series of groundwater wells and is not connected with a municipal system. Because 60 percent of the permanent employees of SPS reside in Isle of Wight, James City, or Surry Counties or the City of Newport News, discussion of public water supply systems will focus on these four areas.

Isle of Wight County has municipal water supply systems in the towns of Windsor, Smithfield, and Franklin. Permitted groundwater wells supply these systems; Table 2-5 shows average daily use and maximum daily capacity.

Surry County has municipal water supply systems in the towns of Claremont, Dendron, and Surry. A fourth system is under construction at the County's industrial park 2 miles west of the town of Surry off State Highway 10. These systems are supplied by permitted groundwater wells; Table 2-6 shows average daily use and maximum daily capacity for these systems.

The municipal water supply for James City County is provided by the Newport News Waterworks (Waterworks) described below and the James City Service Authority (JCSA). The JCSA's water system consists of the central system with 29 well facilities and 9 independent water systems with 5 well facilities. Approximately 240 miles of transmission and distribution lines supply about 3.1 million gallons of water per day to 10,050 customers (Ref. 2.10-4). The JCSA has a groundwater withdrawal permit for 4.78 million gallons per day. This amount of water will meet the County's needs through 2008, and an additional 4 million gallons per day will be needed to meet demand through 2040. The JCSA is pursuing an initiative to meet its long-term water demand by participating in a regional effort to supplement the JCSA groundwater with surface water. James City County has joined Newport News in pursuing the construction of a water supply reservoir on Cohoke Creek in King William County to supply 26 million gallons per day. This project is scheduled to be completed in 2005. James City County intends to contract with Newport News to obtain the rights to at least 2 and possibly 4 million gallons per day from the project. Water supply needs in the intermediate term will be met with three replacement wells and two new wells to provide an additional 2 million gallons per day (Ref. 2.10-4).

Public water supply for Newport News is provided by the Waterworks, one of the 100 largest water utilities in the United States and one of the three largest in the Commonwealth of Virginia. Water is supplied to nearly 400,000 residents of Poquoson, Hampton, and Newport News, and to portions of York and James City Counties. The primary source of raw water is the Chickahominy River. Secondary sources and storage include five reservoirs: Diascund Creek, Little Creek, Skiffe's Creek, Lee Hall, and Harwood's Mill. A sixth reservoir is proposed on Cohoke Creek in King William County, as discussed above. The Waterworks operates two water treatment plants: Lee Hall and Harwood's Mill. Lee Hall has a maximum rated treatment capacity of 54 million gallons per day, and Harwood's Mill is currently rated to treat 31 million gallons per day (Ref. 2.10-5).

As of 1995, water demand equaled the safe yield of the Waterworks' surface water supplies. As stated above, Waterworks is in the process of permitting and constructing a new surface reservoir system in King William County to add additional capacity by 2005. As an interim measure, a reverse osmosis membrane treatment facility is being constructed. This facility will treat brackish groundwater from two deep confined aquifers within the coastal plain of Virginia. Six production wells will supply 6 million gallons per day (Ref. 2.10-5).

The Waterworks has implemented a program aimed at fostering water conservation by system users and has helped to form a regional water conservation team as additional ways to meet future water demands.

2.10.2 Transportation

Road access to SPS is via State Highway 650, which is a two-lane paved road. State Highway 650 intersects State Highway 10 approximately 5 miles from the plant. State Highway 650 carries a level of service (LOS) designation of "A". State Highway 10 in the vicinity of SPS, from Surry County Courthouse to the divergence of the business and bypass State Highway 10 north of Smithfield, carries an LOS designation of "C". Employees commuting to James City County would use State Highway 31 from Surry Courthouse to the James Ferry at Scotland. That section of State Highway 31 (Figure 2-1) carries an LOS designation of "B" (Ref. 2.10-6). The following table compares the characteristics of the different LOS designations.

Level of Service Designation Characteristics

Level of Service	Conditions
A	Free flow of the traffic stream; users are unaffected by the presence of others.
B	Stable flow in which the freedom to select speed is unaffected, but the freedom to maneuver is slightly diminished.
C	Stable flow that marks the beginning of the range of flow in which the operation of individual users is significantly affected by interactions with the traffic stream.

Source: Ref. 2.6-1, Section 3.7.4.2.

The Virginia Department of Transportation operates the ferry service across the James River between Scotland and Jamestown. Two ferries run seven days a week and a third ferry is added during the summer months. Capacity for the larger ferry is 75 to 80 vehicles and for the two smaller ferries is 50 to 55 vehicles. Weight restrictions for all three ferries are 16 tons per vehicle and 28 tons per semi-trailer combination. Ferries operate 24 hours a day, leaving the dock every half-hour except during peak traffic hours, when they leave every 20 to 25 minutes. Ferry traffic has been increasing over the last several years. The Virginia Department of Transportation has implemented schedule adjustments to accommodate the increased use and feels that further adjustments are possible to accommodate future growth in ferry traffic (Ref. 2.10-7).

Jamestown Ferry.

2.11 Minority and Low-Income Populations

Dominion used U.S. Nuclear Regulatory Commission (NRC) guidance (Ref. 2.11-1, Attachment 4) and 1990 census data from the U.S. Census Bureau website (Ref. 2.11-2) to identify minority and low-income populations in the vicinity of SPS. Dominion used ArcView® software to combine Census Bureau tract data with Environmental Systems Research Institute (Ref. 2.11-3) tract-boundary spatial data to produce tract-by-tract data and maps. Dominion used the states of Virginia and North Carolina as the geographic region for comparison against tract-specific data within each state. The Census Bureau provides updated annual population projections for selected portions of its demographic information; however, the updated projections are not available for census tract levels of analysis. For this reason, Dominion chose to use 1990 census data for all demographic analyses so that the data sets are comparable throughout the environmental report.

In order to determine if environmental justice reviews are necessary for the license renewal of SPS, the demographics of the area of impact were examined to determine if minority and/or low-income populations are present. Five hundred eleven census tracts make up the 50-mile radius surrounding the SPS site which, for this analysis, is considered the environmental impact area. Census tracts were included in this analysis, if at least 50 percent of the land area lay within the 50-mile radius. Table 2-7 presents population summaries for the counties/independent cities, as well as the states of Virginia and North Carolina.

2.11.1 Minority Populations

As defined in the Guidance for Preparing Environmental Assessments and Considering Environmental Issues (Ref. 2.11-1, Attachment 4), minority populations are considered to be present if:

<u>exceeds 50 percent</u> - the minority population of the environmental impact site exceeds 50 percent, or

<u>more than 20 percent greater</u> - the minority population percentage of the environmental impact site is significantly greater (typically at least 20 percent) than the minority population percentage in the geographic area chosen for comparative analysis.

Dominion used the state as the geographic area chosen for purposes of comparative analysis.

Although the population of the environmental impact site as a whole does not constitute a Black minority population under NRC guidance, the environmental impact site does have 170 census tracts that are considered to have Black minority populations under NRC guidance. The environmental impact site also has one Native American minority tract and one Asian minority tract. These tracts may not be exclusively populated by Black, Native American, or

Asian populations, but may have more than one minority presence. Figure 2-4 identifies the predominant minority in each tract, if one exists, and the location of each tract relative to SPS. As illustrated in Figure 2-4, Black minority populations exist throughout the area of impact. One Native American minority tract in Charles City County, located 25 miles northwest of SPS, is home to the Chickahominy Tribe. There are two Native American reservations located within the environmental impact site: the Mattaponi and the Pamunkey Reservations located in King William County. However, the Native American populations associated with these reservations are not large enough to classify the tracts as minority. The Asian minority tract is located in the City of Norfolk, but is very small and therefore does not appear on the map due to scale.

2.11.2 **Low-Income Populations**

NRC guidance defines "low-income" using U.S. Census Bureau statistical poverty thresholds (Ref. 2.11-1, Attachment 4). The guidance indicates that a low-income population is present if the percentage of households below the poverty level in an environmental impact site is significantly greater (typically at least 20 percent) than the low-income population percentage in the geographical area chosen for comparative analysis.

Low-income populations are present in 52 tracts throughout the environmental impact site. These 52 tracts, all in Virginia, exceed the state average of households below the poverty level (10.52 percent) by 20 percent or more. They represent 10 percent of the tracts within the environmental impact site. Figure 2-5 presents the geographic location of those census tracts that have a low-income population.

2.12 Meteorology and Air Quality

Surry County, where SPS is located, is part of the State Capital Intrastate Air Quality Control Region (AQCR). The AQCR is designated as being in attainment for carbon monoxide, sulfur dioxide, nitrogen dioxide, particulate matter with an aerodynamic diameter $\leq$10 microns, and lead.

Virginia has been designated as being in nonattainment for the 1-hour ozone standard. Virginia will likely be designated nonattainment as well, with respect to the new, more stringent 8-hour ozone standard, although this new 8-hour standard, promulgated in 1997, is currently not enforceable, pending further order of the U.S. District Court of Appeals in the District of Columbia Circuit.

2.13 Historic and Archaeological Resources

Although nothing of historic or archaeological significance was noted during the construction of the nuclear facilities in the 1970s, there are numerous historic sites near SPS (Ref. 2.13-1, pg. 7). Within Surry County, 16 sites are currently listed on the National Register of Historic Places (Ref. 2.13-2). Table 2-8 lists these sites. Several colonial era sites (Bacon's Castle, Chippokes Plantation, Smith's Fort, Old Brick Church, and Four Mile Tree) are in the vicinity. Chippokes Plantation is closest (2 miles) to SPS and has Late Archaic and Woodland Period sites, as well as 17th through 20th century sites (Ref. 2.13-3, pp. 4-5). The SPS transmission line corridors do not cross any known historic sites and do not appear to cross any archaeological sites. The peninsula formed by the York and James Rivers north of SPS contains many historic sites, including plantations, colonial homes, battlefields, and prehistoric and Native American sites (Ref. 2.13-4). The greatest concentration of sites is within the Colonial Historic Park and Williamsburg in York and James City Counties, respectively. Other sites of historic interest, related to the Revolutionary and Civil Wars, are in the vicinity of Petersburg, Richmond, and Hampton Roads.

TABLES AND FIGURES

Table 2-1
Aquifers Beneath Surry Power Station

Geologic Age	Hydrologic Unit	Formation	Physical Description	Water-Bearing Properties/ Yield	Approximate Formation Thickness at SPS (feet)[a]	Approximate Aquifer Elevation at SPS (feet above msl)
Pleistocene to Pliocene	Columbia Aquifer (Water Table)	Shirley and Upper Norfolk	Interbedded sand, gravel, silty sand, silt, clay, and peat	Low to moderate	100	-80 to 25
Pliocene	Yorktown Confining Unit	Yorktown	Stiff clay		15	
Pliocene	Yorktown-Eastover Aquifer	Yorktown	Isolated compact sand and silt	Low to moderate	55	-75 to -20
Miocene	St. Marys Confining Unit	Lower Yorktown and St. Marys	Stiff clay, isolated compact sand, and silt		50	
Miocene	Calvert Confining Unit	Calvert	Stiff clay, isolated compact sand, and silt		50	
Upper Eocene	Chickahominy-Piney Point Aquifer	Chickahominy	Sandy clay	Low to moderate	(50)	-225 to -175
Lower – Middle Eocene	Nanjemony-Marlboro Clay Confining Unit	Nanjemony	Marl, thin limestone, and sand		65	
Lower Eocene	Aquia Aquifer	Aquia	Glauconitic marl and basal sand	75 to 200 gpm		-320 to -290
Cretaceous	Upper Potomac Confining Unit	Potomac	Clay		30	

Table 2-1 (continued)
Aquifers Beneath Surry Power Station

Geologic Age	Hydrologic Unit	Formation	Physical Description	Water-Bearing Properties/ Yield	Approximate Formation Thickness at SPS (feet)[a]	Approximate Aquifer Elevation at SPS (feet above msl)
Cretaceous	Upper Potomac Aquifer	Potomac	Sand	75 to 220 gpm[b]	(85)	-435 to -350
Cretaceous	Middle Potomac Confining Unit	Potomac	Clay		15	
Cretaceous	Middle Potomac Aquifer	Potomac	Sand	Up to 940 gpm	(500)	-950 to -450
Cretaceous	Lower Potomac Confining Unit	Potomac	Clay		40	
Cretaceous	Lower Potomac Aquifer	Potomac	Sand		500	-1,375 to -875
Precambrian		Basement	Metamorphosed igneous and sedimentary rock	(NA)	(NA)	-1,375

Source: Ref. 2.1-1, pg. 2.4-47 and 2.3-2, pg. 2-3.
gpm = gallons per minute.
NA = not applicable.
a. Numbers is parentheses were based on analyst calculations, not on data in references.
b. Pump rates are from site wells.

Table 2-2
Threatened or Endangered State and Federal Species that Occur or Could Possibly Occur at Surry Power Station and/or Along Associated Transmission Lines

Scientific Name	Common Name	Federal Status[a]	Commonwealth Status[a,b]
Mammals			
Plecotus rafinesquii	Eastern big-eared bat	-	E
Sorex longirostris fisheri	Dismal Swamp southeastern shrew	T	T
Birds			
Charadrius melodus	Piping plover	T	T
Falco peregrinus	Peregrine falcon	-	E
Haliaeetus leucocephalus	Bald eagle	T	T
Lanius ludovicianus	Loggerhead shrike	-	T
Reptiles			
Crotalus horridus atricaudatus	Canebrake rattlesnake	-	E
Amphibians			
Ambystoma mabeei	Mabee's salamander	-	T
Ambystoma tigrinum	Tiger salamander	-	E
Hyla gratiosa	Barking treefrog	-	T
Fish			
Acipenser brevirostrum	Shortnose sturgeon[c]	E	E
Acipenser oxyrhynchus	Atlantic sturgeon	Ca	(d)
Enneacanthus chaetodon	Blackbanded sunfish	-	E
Invertebrates			
Cicindela dorsalis dorsalis	Northeastern beach tiger beetle	T	-

**Table 2-2 (continued)
Threatened or Endangered State and Federal Species that Occur or Could Possibly Occur at Surry Power Station and/or Along Associated Transmission Lines**

Scientific Name	Common Name	Federal Status[a]	Commonwealth Status[a,b]
Vascular Plants			
Aeschynomene virginica	Sensitive joint-vetch	T	-
Bacopa innominata	Tropical water-hyssop	-	E

a. T = Threatened; E = Endangered; Ca = Candidate for Federal listing; - = Not listed.
b. A third state category, "special concern" has been excluded from this table. "Special concern" is not a legal category, but identifies species about which the state is concerned.
c. The shortnose sturgeon is listed as "extinct and extirpated" by the VDCR Natural Heritage Program.
d. The Atlantic Sturgeon is a "special concern" species in Virginia.

Table 2-3
Estimated Populations and Annual Growth Rates in Isle of Wight, James City, and Surry Counties and City of Newport News from 1980 – 2030

	Isle of Wight County		James City County		Surry County		City of Newport News	
Year	Population	Average Annual Growth (as %)	Population	Average Annual Growth (as %)	Population	Average Annual Growth (as %)	Population	Average Annual Growth (as %)
1980	21,603[a]	1.8	22,763[a]	2.8	6,046[a]	0.3	144,903[a]	0.5
1990	25,053[a]	1.6	34,859[a]	5.3	6,145[a]	0.2	170,045[a]	1.7
2000	29,499[b]	1.8	48,000[b]	3.8	6,599[b]	0.7	180,999[b]	0.6
2010	34,098[b]	1.6	60,000[b]	2.5	7,095[b]	0.8	189,998[b]	0.5
2020	38,726[c]	1.3	72,076[c]	2.0	7,594[c]	0.7	199,054[c]	0.5
2030	43,325	1.2	84,076	1.7	8,090	0.7	208,053	0.5

a. Ref. 2.6-5.
b. Ref. 2.6-6.
c. Ref. 2.6-7.

Table 2-4
Property Tax Revenues Generated in Surry County, Virginia; Property Taxes Paid to Surry County by Surry Power Station; and Surry County Operating Budget, 1995 – 1998

Year	Total Surry County Property Tax Revenues[a]	Property Tax Paid to Surry County by SPS[b]	Percent of Total Property Taxes	Operating Budget for Surry County[c]
1995	$10,929,247	$8,339,169	76	$16,737,107
1996	$11,763,226	$8,994,835	76	$16,818,954
1997	$12,463,315	$9,428,802	76	$18,156,965
1998	$12,208,208	$9,154,251	75	$18,589,526

a. Ref. 2.8-2.
b. Ref. 2.8-1.
c. Ref. 2.8-3 .

Table 2-5
Isle of Wight County Water Suppliers and Capacities

Water Supplier	Average Daily Use (Gallons per day)	Maximum Daily Capacity (Gallons per day)
Windsor	9,000	530,000
Smithfield	30,000	3,200,000
Franklin	65,000	1,500,000

Source: Ref. 2.10-1.

Table 2-6
Surry County Water Suppliers and Capacities

Water Supplier	Source	Average Daily Use (Gallons per day)	Maximum Daily Capacity (Gallons per day)
Claremont[a]	2 wells	25,000	50,000
Dendron[a]	2 wells	20,000	60,000
Surry[a]	3 wells	40,000	100,000
Industrial Park[b]	1 well	80,000	150,000

a. Ref. 2.10-2.
b. Ref. 2.10-3.

Table 2-7
State and County Minority and Low-Income Population Percentages[a]

County/Independent City Demographics	State	White %	Black %	Native American %	Asian %	Other Non-Hispanic %	Hispanic %	Low Income %
State Demographics								
	North Carolina	75	22	1	1	<1	1	14
County Demographics								
Gates	North Carolina	52	48	0	<1	0	0	17
Commonwealth Demographics								
	Virginia	76	19	<1	2	<1	3	11
County/Independent City Demographics								
Charles City	Virginia	29	63	8	<1	0	1	17
Chesapeake*	Virginia	67	31	<1	1	<1	1	11
Chesterfield	Virginia	77	19	<1	2	<1	1	8
Colonial Heights*	Virginia	96	<1	<1	2	<1	1	7
Dinwiddie	Virginia	74	25	<1	<1	0	1	11
Essex	Virginia	80	19	<1	0	0	<1	15
Franklin*	Virginia	49	50	<1	<1	<1	<1	22
Gloucester	Virginia	88	11	<1	1	0	1	11
Hampton*	Virginia	48	48	<1	2	<1	2	14
Hanover	Virginia	93	5	<1	1	<1	1	4
Henrico	Virginia	63	35	<1	<1	<1	1	8
Hopewell*	Virginia	67	31	<1	1	<1	2	17

Table 2-7 (continued)
State and County Minority and Low-Income Population Percentages[a]

County/Independent City Demographics	State	White %	Black %	Native American %	Asian %	Other Non-Hispanic %	Hispanic %	Low Income %
Isle of Wight	Virginia	67	32	<1	<1	<1	<1	12
James City	Virginia	78	19	<1	1	<1	1	7
King and Queen	Virginia	57	41	1	<1	<1	<1	17
King William	Virginia	65	32	3	<1	0	<1	12
Lancaster	Virginia	69	30	<1	<1	0	1	15
Mathews	Virginia	85	13	<1	<1	<1	1	12
Middlesex	Virginia	74	25	<1	<1	0	1	15
New Kent	Virginia	76	21	1	<1	<1	1	6
Newport News*	Virginia	59	36	<1	2	<1	3	16
Norfolk*	Virginia	57	38	<1	3	<1	2	17
Northampton	Virginia	48	50	<1	0	<1	2	27
Petersburg*	Virginia	25	73	<1	1	<1	1	23
Poquoson*	Virginia	98	<1	<1	1	<1	<1	4
Portsmouth*	Virginia	47	50	<1	1	<1	2	20
Prince George	Virginia	64	29	<1	2	<1	4	5
Richmond*	Virginia	27	71	<1	1	<1	1	25
Southampton	Virginia	51	47	<1	<1	0	2	17
Suffolk*	Virginia	52	47	<1	<1	<1	1	18
Surry	Virginia	44	55	<1	<1	0	<1	17

Table 2-7 (continued)
State and County Minority and Low-Income Population Percentages[a]

County/Independent City Demographics	State	White %	Black %	Native American %	Asian %	Other Non-Hispanic %	Hispanic %	Low Income %
Sussex	Virginia	42	58	<1	<1	<1	<1	21
Virginia Beach*	Virginia	80	13	<1	3	<1	3	5
Williamsburg*	Virginia	87	11	<1	2	<1	1	23
York	Virginia	81	16	<1	2	<1	1	6

a. Based on 1990 Census Data; rounded to nearest whole number.
* - Independent City.

Table 2-8
Surry County, Virginia, Sites on the National Register of Historic Places

Site Name	Location
Bacon's Castle	Off State Highway 10 in Bacon's Castle
Chippokes Plantation	Chippokes State Park, State Highways 634 and 633
Enos House	Surry County (address restricted)
Four Mile Tree	Northeast of the junction of State Highways 618 and 610
Glebe House of Southwark Parish	East of Spring Grove on State Highway 10
Melville	East of Town of Surry
Montpelier	1.4 miles southwest of Cabin Point
Old Brick Church	State Highway 10 in Bacon's Castle
Pleasant Point	1 mile south of Town of Scotland on State Highway 637
Rich Neck Farm	East of Town of Surry
Second Southwark Church Archaeological Site (44SY65)	Surry County (address restricted)
Smith's Fort	Surry County (address restricted)
Snow Hill	State Highway 40 Gwaltney Corner
Surry County Courthouse Complex	State Highway 10 in Town of Surry
Swann's Point Plantation Site	Town of Scotland (address restricted)
Warren House	Northeast of Town of Surry off State Highway 31

Source: Ref. 2.13-1.

Figure 2-1
Dominion - 50 Miles Surry Vicinity Map

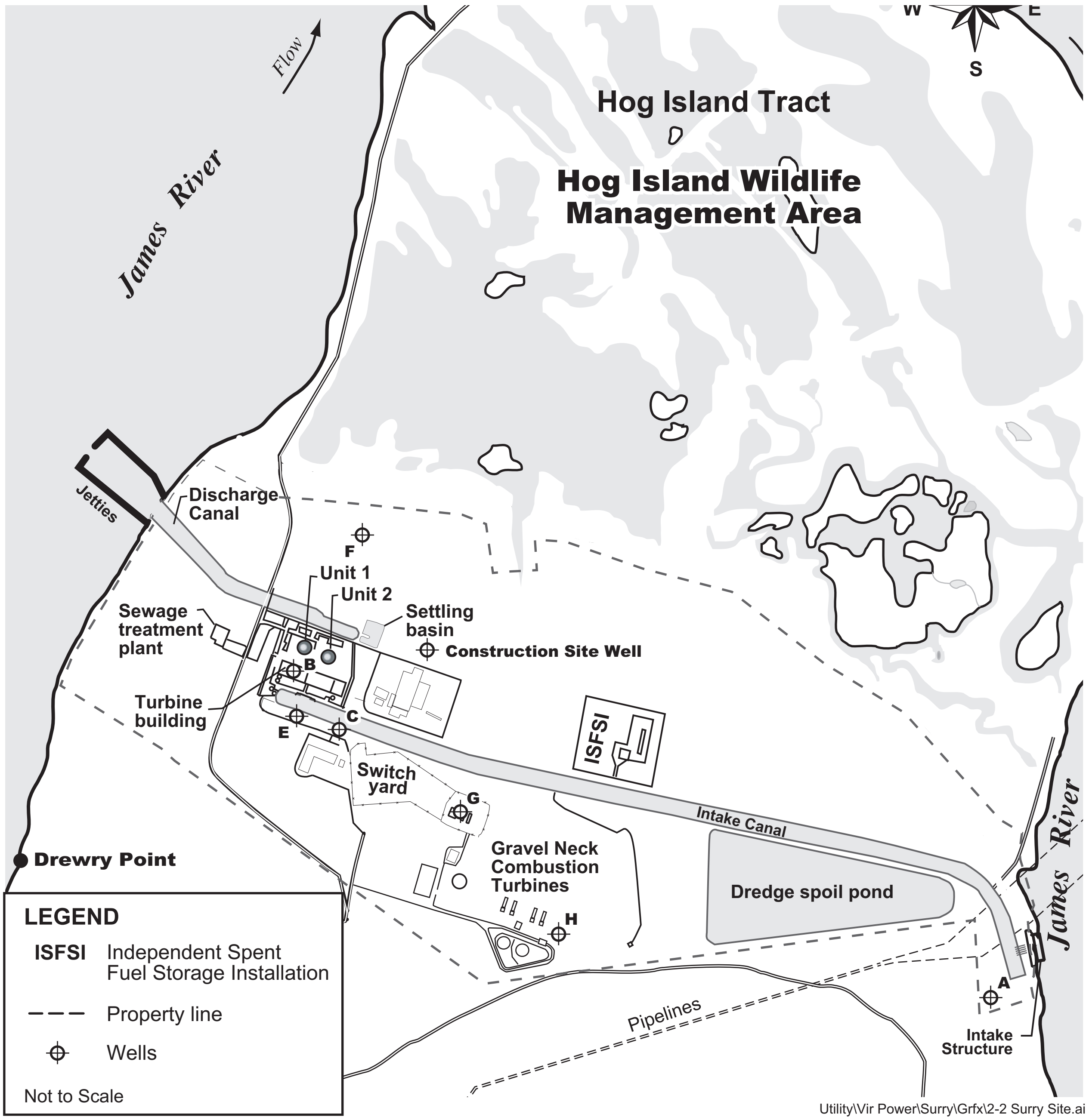


Figure 2-2
Dominion - SPS Site

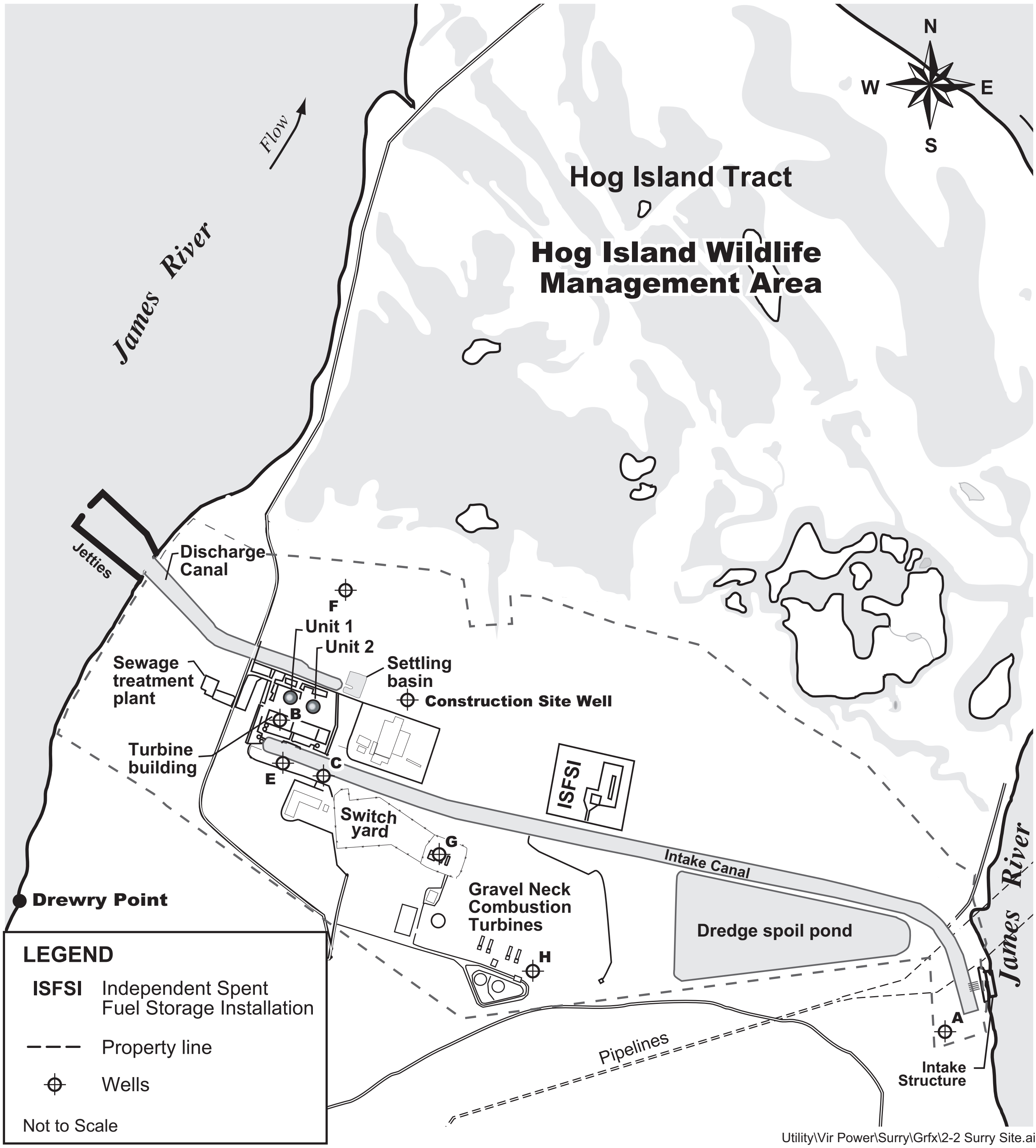


Figure 2-3
Dominion - 6 Miles Surry Vicinity Map

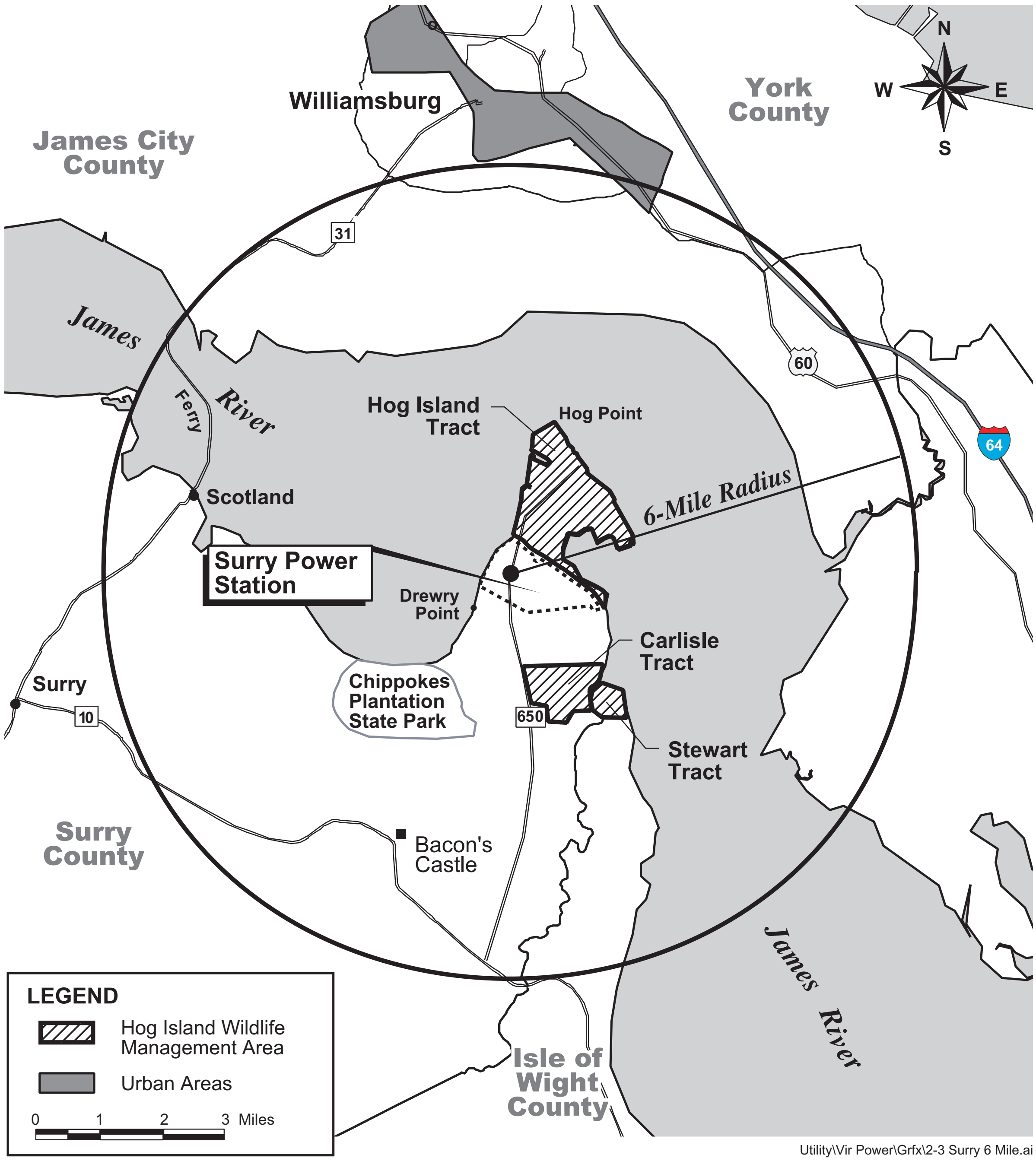


Figure 2-4
Dominion - SPS Minority Population

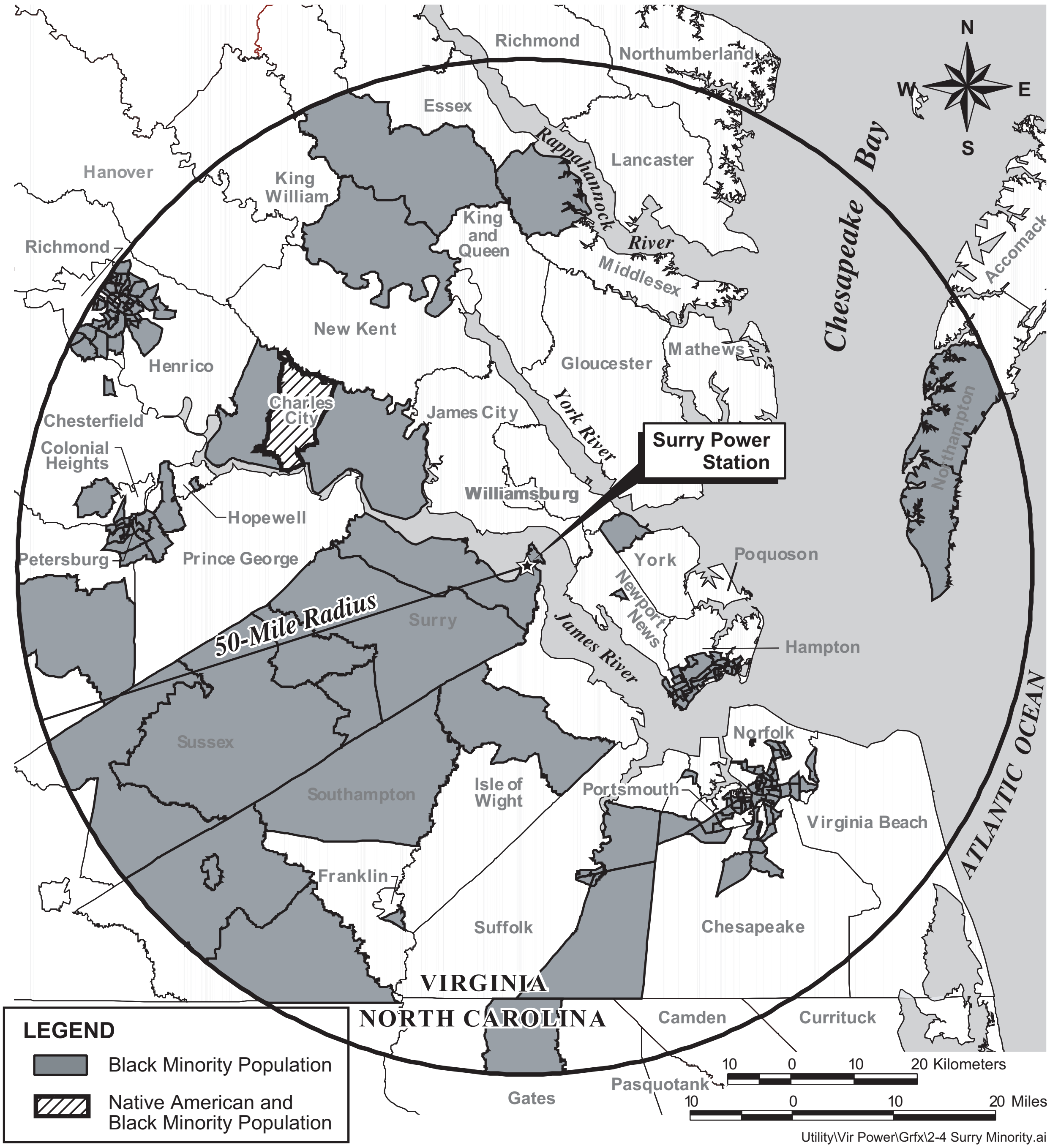
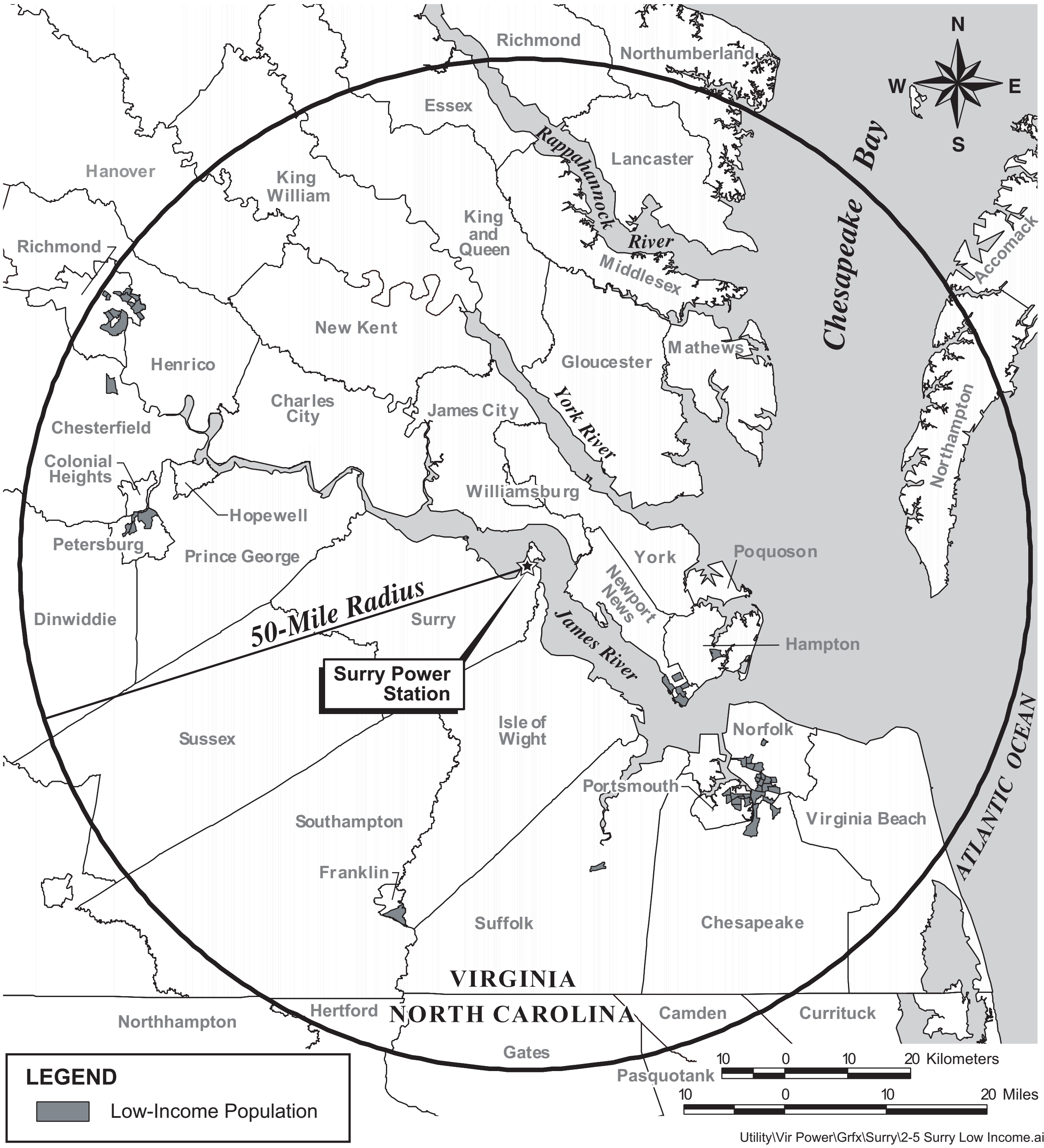


Figure 2-5
Dominion - SPS Low-Income Population



Utility\Vir Power\Grfx\Surry\2-5 Surry Low Income.ai

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3.0 PROPOSED ACTION

NRC Input

"...The report must contain a description of the proposed action, including the applicant's plans to modify the facility or its administrative control procedures.... This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment...." 10 CFR 51.53(c)(2)

Dominion proposes that the U.S. Nuclear Regulatory Commission (NRC) renew the operating licenses for Surry Power Station Units 1 and 2 (SPS) for an additional 20 years. Renewal would give Dominion and the Commonwealth of Virginia the option of relying on SPS to meet future needs for electricity. Section 3.1 discusses the plant in general. Sections 3.2 through 3.4 describe potential activities and associated changes in number of employees that license renewal could effect. Section 3.5 discusses the Gravel Neck Combustion Turbines Station which is adjacent to the nuclear facility and shares the switchyard and groundwater withdrawals on the Surry groundwater withdrawal permit.

3.1 General Plant Information

General information about SPS is available in several documents. In 1972, the U.S. Atomic Energy Commission, predecessor agency of NRC, prepared Final Environmental Statements for operation of SPS Units 1 and 2 (Refs. 3.1-1 and 3.1-2). The NRC *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (Ref. 3.1-3) describes SPS features and, in accordance with NRC requirements, Dominion maintains an updated Final Safety Analysis Report for the units (Ref. 3.1-4). Dominion has referred to each of these documents while preparing this environmental report for license renewal.

3.1.1 Reactor and Containment Systems

SPS is a two-unit plant as shown in Figure 3-1. Each unit includes a pressurized light-water reactor and three steam-driven turbine generators manufactured by Westinghouse. The balance of each unit was designed by Dominion with the assistance of its agent, Stone & Webster Engineering Corporation. Each unit was warranted for an output of 2,441 megawatts-thermal (MWt), with a corresponding gross electrical output of 822.6 megawatts-electric (MWe). Units 1 and 2 achieved commercial operation in December 1972 and May 1973, respectively. In 1995, based on an NRC-prepared environmental assessment and finding of no significant impact, both units were uprated to a core power output of 2,546 MWt with a calculated gross output of 855.4 MWe each (Ref. 3.1-5, pg. 32356). Average net capacity is 1,602 MWe for the plant. (Ref. 3.1-6).

Containment domes of SPS Units 1 and 2 and discharge canal.

Each reactor containment structure is a steel-lined, reinforced-concrete, 135-foot-diameter cylinder (Ref. 3.1-4, Figure 15.1-2) with a hemispheric dome and a flat reinforced-concrete foundation mat (Ref. 3.1-4, pg. 5.1-1). Each containment structure is designed to withstand an internal pressure of 45 pounds per square inch gage (psig) above atmospheric pressure (Ref. 3.1-7, pg. 1 of 3). Air pressure inside the containment structure is maintained at about 5 psig below atmospheric pressure for routine operation. Together with its engineered safety features, each containment structure is designed to provide adequate radiation protection for both normal operation and unlikely accidents such as earthquakes, tornadoes, or loss of coolant (Ref. 3.1-4, pp. 5.1-1 and 5.2-5). SPS fuel is slightly enriched uranium dioxide; the current enrichment is 3.20 percent by weight uranium-235 (Ref. 3.1-4, pg. 3.3-13). Dominion operates the reactors at a region average fuel discharge burnup rate of 45,000 megawatt-days per metric ton uranium (Ref. 3.1-4, pg. 3.3-13).

3.1.2 Cooling and Auxiliary Water Systems

3.1.2.1 Surface Water

SPS uses a once-through cooling system to remove waste heat from the reactor-steam electric system and plant auxiliary (service water) systems. Cooling water is withdrawn from the James River through a channel dredged in the riverbed between the main river channel and the eastern shore of Gravel Neck

Peninsula, a distance of approximately 5,700 feet (Ref. 3.1-8, Section 3.2.1). Dominion dredges this channel every 4 to 5 years to maintain a depth of approximately 13 feet. The bottom width of the channel is approximately 150 feet, with a bank slope ratio of 3 (horizontal) to 1 (vertical). These dimensions allow the channel to be used for shipping materials and equipment to a permanent dock located just north of the low-level intake structure.

Circulating water is withdrawn through the low-level intake structure, an eight-bay, reinforced-concrete structure located at the shoreline (western) end of the dredged intake channel. Each of the eight low-level intake bays contains a circulating water pump rated at 210,000 gallons per minute (gpm) (Ref. 3.1-8, Section 3.2.2). When SPS is operating at full power, the eight circulating water pumps move 1,680,000 gpm from the James River to the intake canal. Each pump has an 8-foot-diameter discharge line that conveys the cooling water under an access road, up and over the high-level intake canal embankments, and into the intake canal (Figure 2-2). After circulating through the condensers and service water systems, the water returns to the James River at a point approximately 6 miles upriver from the low-level intake structure.

The low-level intake structure is equipped with a specially-designed Ristroph travelling screen system that was installed in May 1974, approximately two years after Unit 1 came on line. Each of the 8 low-level bays is equipped with a Ristroph screen that consists of 47 panels, each 15 feet wide by 2 feet high, with a screen mesh size of approximately 3/8 inch (Ref. 3.1-8, Section 3.3). Unlike conventional travelling screens, which rotate every 12 to 24 hours (or when a pressure differential develops), the Ristroph units rotate continuously at a speed of 10 feet per minute. This greatly reduces fish mortality because impinged fish are quickly removed from the screens and returned to the James River.

Because the system employs low-pressure spray to gently remove fish from the screens, injuries to fish (such as descaling) are also greatly reduced. Fish washed from the screens are returned (via an underwater pipe) to the James River.

Dominion continues to upgrade the intake structure, traveling screens, and fish flume. For example, Surry is in the process of replacing the original trash racks. In the past Dominion replaced the carbon steel screen structures and hardware with stainless steel and lightweight fiberglass baskets. Dominion removes each screen structure every two years for inspection and maintenance. By the end of 2001, each of the eight screen structures will have new fish deflectors and troughs, and the fish flume will have been replaced. Based on Surry's operations and maintenance of the intake structure and associated equipment, the Virginia Institute of Marine Sciences considers that the performance of these structures is better that it was during the original 316 (b) demonstration (Ref. 3.1-9).

The intake canal conveys circulating water by gravity flow from the low-level intake structures on the James River to the high-level intake structure at the reactors. The canal is approximately 1.7 miles long and is oriented in an east-west direction, nearly bisecting the Gravel Neck Peninsula (Ref. 3.1-8, Section 3.2.3). The canal is lined with concrete to prevent erosion and has an average bottom width of approximately 32 feet. Water levels in the canal vary between 20 and 23 feet above mean sea level (msl), depending on the tidal stage in the James River. At a minimum water level (20 feet above msl), the canal contains approximately 45,000,000 gallons of cooling water (Ref. 3.1-8, Section 3.2.3).

Cooling water moves into two high-level, four-bay intake structures; each structure serves one power station unit. The cooling water is pumped from a high-level intake bay through an 8-foot-diameter pipe to the turbine steam condensers. Service water for auxiliary cooling systems is diverted and withdrawn from the system before the circulating water enters the condensers.

Pipes at low-level intake move water from the James River (on the left), over the canal dike, and into the canal (on the right).

Each condenser was originally equipped with an Amertap condenser cleaning system that circulated sponge rubber balls through the condenser tubes to prevent accumulation of deposits (such as biofouling organisms). In the 1980s, use of the Amertap system at SPS was discontinued in favor of chemical controls. At present, oxidizing biocides (sodium hypochlorite and sodium bromide) are used to control fouling of cooling system components such as condenser tubes. Although instantaneous maximum total residual chlorine concentrations of up to 1.0 milligram per liter are permissible under Virginia Pollutant Discharge Elimination System (VPDES) Permit No. VA0004090, the permit requires SPS to take immediate steps to achieve a nondetectable concentration in the final effluent. When chlorine is detected in an effluent sample, the injection of sodium hypochlorite is discontinued and the concentration in the system normally returns to a nondetectable level in a very short time (less than an hour). To date, SPS has been in compliance with the permitted effluent limitations on chlorine.

After passing through the condensers, the cooling water empties into a 12.5- by 12.5-foot square discharge tunnel and subsequently flows into a common circulating-water discharge canal that conveys the effluent from both units (including the service water discharge) to the James River. The discharge canal ranges in width from 20 feet at its head to 65 feet at its terminus and has an overall length of 2,900 feet (Ref. 3.1-10, Sec. III[A]). The 1,800-foot section of the canal that extends from the power station to the river shoreline is lined with concrete to prevent bank and streambed erosion. Rock-filled jetties projecting perpendicularly from the river shoreline extend the discharge canal another 1,100 feet into the James River (Ref. 3.1-10, Sec. III[A]).

During periods of shutdown, heat is transferred from the primary coolant system through the residual heat removal exchangers to the component cooling water system. The component cooling water heat exchangers then transfer the waste heat to the service water system, which discharges it to the James River via the circulating-water discharge canal. Each SPS unit has its own residual heat removal system, but the component cooling water system and the service water system are shared by both units.

Looking across discharge canal to jetty.

Thermal Effluent Dispersion

At full-power operation, SPS discharges 11.9 x 10^9 British thermal units (Btu)/hr into the James River estuary by way of cooling water discharged into Cobham Bay (Ref. 3.1-10, Sec. III[B]). Dissipation of the thermal plume produced by the warmed water discharge is dependent upon prevailing estuarine and meteorological conditions. The various flow regimes of the estuary, their associated densities and temperatures, wind velocities, ambient air temperatures, and relative humidities affect the size, shape, and rate of dissipation of the plume.

The SPS discharge permit (VPDES Permit No. VA0004090) limits waste heat rejected to the James River from SPS to 12.6 x 10^9 Btu/hr, but does not require the reporting of discharge temperatures. Dominion carried out extensive pre- and post-operational studies on thermal effects of SPS on the James River. These studies were compiled and summarized in a successful Clean Water Act Section 316(a) Demonstration (Ref. 3.1-10). Based on research and monitoring studies that spanned a 7-year period and included computer modeling, field investigations of water quality and aquatic biota, field measurements of water temperatures up- and down-stream of SPS, and continuous electronic monitoring of water temperatures in the SPS intake and discharge canals, temperatures higher than 90° degrees Farenheit (°F) at the SPS outfall normally occur only in the months of June, July, August, and September when SPS is operating at or near full power.

The highest surface temperature recorded in the SPS discharge canal in a comprehensive 5-year study (2 years pre-operational and 3 years post-operational) under a variety of operational conditions was 99.9°F on August 21, 1975 (Ref. 3.1-11, pp. 1, 99). Even in this extreme case, all excess temperatures decreased rapidly as distance from the outfall increased, and temperatures at distances of 3,000 feet or more were rarely greater than 5°F above ambient temperatures in the river.

During a period (August 6 to September 10, 1975) of high ambient water temperatures, when SPS was running at 90 percent or greater capacity, discharge temperatures ranged from 92.8 to 99.9°F (Ref. 3.1-11, pp. 21-23). These temperatures are believed to be typical of those observed in the discharge canal in late summer when both SPS units are operating at or near full power. Temperatures immediately outside the discharge canal in the James River are lower, with the effluent losing 1 to 2°F with every 1,000 feet from the mouth of the discharge canal (Ref. 3.1-11).

3.1.2.2 Groundwater

The SPS site is located within the Eastern Virginia Groundwater Management Area that includes the area east of Interstate 95 and south of the Mattaponi and York Rivers (Figure 3-2). Virginia established groundwater management areas to allow the Commonwealth to better manage its groundwater resources. SPS received its first groundwater withdrawal permit under the Virginia Groundwater Management Act on August 1, 1999.

There are 10 permitted operating groundwater wells on the SPS site. Of these 10 wells, 7 serve the nuclear plant and 3 serve the fossil plant (see Section 3.5). Dominion has been permitted by the Commonwealth of Virginia's Department of Environmental Quality (VDEQ) to withdraw from the 10 wells a total of 154.703 million gallons per year (294 gpm) with a monthly maximum of 15.89 million gallons for use as domestic, process, and cooling water. These wells vary from 396 feet to 420 feet deep and are screened in sediments in the upper zone of the Cretaceous Potomac aquifer (Ref. 3.1-12, pp. 1, 2). Based on the annual reports of water withdrawal (Ref. 3.1-13 to 3.1-20) for 1992 through 1999, the SPS groundwater use amounts to approximately 116 million gallons per year (9.7 million gallons per month or approximately 221 gpm) (Table 3-1). Three of the SPS wells are capable of yields up to 220 gpm (based on specific-capacity tests) and produce makeup, domestic, and fire protection water at SPS. A well that supplies the SPS Training Center is capable of pumping 100 gpm (Ref. 3.1-4, pg. 2.3-10). The other nuclear plant wells are less productive. The three wells that supply Gravel Neck draw a yearly maximum of 4.7 million gallons (9 gpm) at peak groundwater use.

As part of the groundwater withdrawal permit, Dominion is required to determine whether impacts to pre-existing users exist and to mitigate these if possible. Dominion also is required to develop a water conservation and management plan and to utilize water-saving processes and initiate a water loss reduction program (Ref. 3.1-21). Dominion will submit these studies to VDEQ as part of the groundwater withdrawal permit renewal process in the year 2009.

Surry transmission lines with row crop planted in right-of-way.

3.1.3 Transmission Facilities

Dominion built nine transmission lines for the specific purpose of connecting SPS to the transmission system. Beginning at SPS, these transmission lines occupy two corridors that run in a southerly direction and that ultimately branch to five corridors (see Figure 3-3). "Corridor" is a general term used to identify the land over which a transmission line travels. A utility may own the land, in which case it holds the corridor as a property owner. More commonly, others own the land and the utility owns the right, called an easement, to install and maintain the transmission line on the land. In the case of an easement, the corridor is commonly called a right-of-way. Most Surry transmission line corridors are rights-of-way, with a small percentage (less than 1 percent) of the acreage owned outright.

The list below identifies each transmission line by the line number and name of the substation at which each line connects to the overall electric power grid. The accompanying paragraphs provide other features of the transmission lines, including voltage, right-of-way width and length, and existence of other lines in the right-of-way.

- Lines 212 and 240 to Hopewell – There are two 230-kilovolt (kV)[1] lines to the Hopewell Substation near Hopewell, Virginia. Lines 212 and 240 share towers on this corridor. Another Surry line (number 567) shares the corridor for approximately 30 miles. The overall length of the two Hopewell lines is nearly 43 miles. The right-of-way width varies from 120 feet (over the last 13 miles) to 350 feet (over the first 11 miles where several lines share the corridor).
- Line 214 to Whealton – The line to the Whealton Substation in Hampton, Virginia, operates at 230 kV. Initially, the corridor is shared with four other Surry lines (223, 226, 290, and 578). Lines 214 and 226 share the same towers. Although line 214 does not connect to the Chuckatuck Substation, the line branches northeast there and continues across the James River in a corridor shared with line 263 (not a Surry line). The Whealton line runs approximately 24 miles to Chuckatuck and then an additional 14 miles into Hampton for a total of nearly 38 miles. The right-of-way width varies from 105 to 450 feet.
- Line 223 to Yadkin – This 230-kV line provides power to the Yadkin Substation near Portsmouth, Virginia. Initially, its corridor is shared with four other Surry lines (214, 226, 290, and 578). Line 223 shares towers with line 290 until the Chuckatuck Substation. After Chuckatuck, line 223 shares towers with line 226, which eventually terminates at the Churchland Substation. The overall length of line 223 is approximately 43 miles. The right-of-way width varies from 125 to 450 feet, depending on local conditions and the number of lines in the corridor. (Line 531 also runs from Surry to Yadkin but through another corridor).
- Line 226 to Churchland – The 230-kV line provides power to the Churchland Substation in Portsmouth, Virginia. This line initially shares the corridor with four other Surry lines (214, 223, 290, and 578). The line shares towers with line 214. After passing through the Septa and Chuckatuck Substations without connecting to them, line 226 branches east into Portsmouth, while line 223 continues south to Yadkin. The branch corridor into the Churchland Substation contains lines 87, 226, and 267 (only 226 is a Surry line). The

1. A primary characteristic of a transmission line is the voltage, measured in kilovolts (kV). The GEIS indicates that transmission lines use voltages of approximately 115 to 138-kV and higher and that, in contrast, distribution lines use voltages below 115 or 138-kV (Ref. 3.1-3, Section 4.5.1, pp. 4-59). The Surry Plant transmission lines operate at one of two voltages: either 230-kV or 500-kV).

overall length of line 226 is about 39 miles. The right-of-way width varies from 125 to 450 feet.

- Line 290 to Chuckatuck – Line 290 provides power at 230 kV to the Chuckatuck Substation north of Suffolk, Virginia. This line initially shares the corridor with four other Surry lines (214, 223, 226, and 578). The line shares towers with line 223. The Chuckatuck line runs approximately 11 miles where it bypasses the Septa Substation, then an additional 12 miles for a total of almost 24 miles. The right-of-way width varies from 295 to 450 feet.
- Line 531 to Yadkin – This 500-kV line to the Yadkin Substation near Portsmouth, Virginia, follows a different corridor than line 223, which also terminates in Yadkin. This line initially shares the corridor with three other Surry lines (212, 240, and 567). However, farther down this corridor, the Yadkin line branches south and runs either alone or with other non-Surry lines. At nearly 51 miles, line 531 is the second longest of the Surry transmission lines. It passes through the Suffolk Substation without connecting. The right-of-way width varies from 150 to 350 feet.
- Line 567 to Chickahominy – Line 567 provides power at 500 kV to the Chickahominy Substation in Providence Forge, Virginia. This line initially shares the corridor with three other Surry lines (212, 240, and 531). Six miles after leaving Surry, line 531 branches to the south leaving lines 212, 240, and 567 to share this westward running corridor. After an additional 34 miles, line 567 branches northwest for the nearly 15-mile run into Providence Forge. The total length of this line is approximately 54 miles. The right-of-way width varies from 150 to 350 feet.
- Line 578 to Septa – At nearly 12 miles, the 500-kV line to the Septa Substation near Surry, Virginia, is the shortest of the Surry transmission lines. It shares the corridor with lines 214, 223, 226, and 290. The right-of-way width initially is 240 feet, but widens to 350 feet for the remaining 11 miles.

In total, for the specific purpose of connecting Surry to the transmission system, Dominion has approximately 300 miles of transmission lines (170 miles of corridor) that occupy approximately 5,000 acres. Dominion plans to maintain these transmission lines, which are integral to the larger transmission system, indefinitely. They will remain a permanent part of the transmission system after Surry is decommissioned, because six combustion turbine generators on the Surry site also use these lines to distribute power to the grid (see Section 3.5).

Surry transmission line corridors pass through land that is primarily a mixture of cultivated land, grazing land, and managed timberlands (paper and pulp stock). Corridors that pass through farmlands generally continue to be used in this fashion. Corridors in timberlands and in the vicinity of road crossings are maintained on a 3-year cycle by mowing or, if inaccessible to mowers, by use of nonrestricted-use herbicides.

Dominion designed and constructed all Surry transmission lines in accordance with the 6th edition (1961) of the National Electrical Safety Code® and industry guidance that was current when the lines were built. Ongoing right-of-way surveillance and maintenance of Surry transmission facilities, which include routine aerial patrols, and triennial helicopter and ground inspections, ensure continued conformance to current standards. Routine aerial patrols of some corridors are conducted annually and include checks for encroachments, broken conductors, and broken or leaning structures, any of which would be evidence of clearance problems. Slow helicopter inspections are conducted to allow more careful checks of facilities and rights-of-way as part of the 3-year inspection cycle. Once every 3 years, all lines are inspected from the ground and measured for clearance at questionable locations. Problems noted during any inspection are brought to the attention of the appropriate organizations for corrective action.

3.2 Refurbishment Activities

NRC Input

"… The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures…. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

"… The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals, and (2) refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item…." Ref. 3.1-3, Section 2.6.3.1, pg. 2-41. (SMITTR defined at GEIS Section 2.4, pg. 2-30, as surveillance, monitoring, inspections, testing, trending, and recordkeeping.)

Dominion has addressed refurbishment activities in this environmental report in accordance with NRC regulations and complementary information in the NRC GEIS for license renewal (Ref. 3.1-3, Section 2.6.2). NRC requirements for the renewal of operating licenses for nuclear power plants include the preparation of an integrated plant assessment (IPA) (10 CFR 54). The IPA must identify and list structures, systems, and components (SSCs) subject to an aging management review. SSCs that are subject to aging and might require refurbishment include, for example, the reactor vessel, piping, supports, and pump casings (see 10 CFR 54.21 for details) that are not subject to replacement periodically.

In turn, the NRC regulations for implementing the National Environmental Policy Act require environmental reports to describe in detail and assess the environmental impacts of refurbishment activities such as planned modifications to SSCs or plant effluents (10 CFR 51.53(c)(2)]. Resource categories to be evaluated for impacts of refurbishment include terrestrial resources, threatened and endangered species, air quality, housing, public utilities and water supply, education, land use, transportation, and historic and archaeological resources.

The GEIS (Ref. 3.1-3) provides helpful information on the scope and the preparation of refurbishment activities to be evaluated in this environmental report. It describes refurbishment activities that utilities might perform for license renewal. Performing such refurbishment activities would necessitate changing administrative control procedures and modifying the facility. The GEIS analysis assumed that an applicant would begin any refurbishment work shortly after NRC granted a renewed license and would complete the activities during five outages, including one major one at the end of the 40th year of operation. The GEIS refers to this as the refurbishment period.

GEIS Table B.2 lists license renewal refurbishment activities that NRC anticipated utilities might undertake. In identifying these activities, the GEIS intended to encompass actions that typically take place only once, if at all, in the life of a nuclear plant. The GEIS analysis assumed that a utility would undertake these activities solely for the purpose of extending plant operations beyond 40 years, and would undertake them during the refurbishment period. The GEIS indicates that many plants will have undertaken various refurbishment activities to support the current license period, but that some plants might undertake such tasks only to support extended plant operations.

Dominion has performed some major construction activities at SPS (e.g., steam generator replacement). However, the SPS IPA that Dominion conducted under 10 CFR 54 has not identified the need to undertake any refurbishment or replacement actions to maintain the functionality of important SSCs during the SPS license renewal period. Dominion has included the IPA as part of this application.

3.3 Programs and Activities for Managing the Effects of Aging

NRC Input

"…The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures…. This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

"…The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals, and (2) refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item…." Ref. 3.1-3, Section 2.6.3.1. (SMITTR is defined in Ref. 3.1-3, Section 2.4, as surveillance, monitoring, inspections, testing, trending, and recordkeeping.)

Appendix B of the license application contains a summary description of the programs and activities for managing the effects of SPS aging. In addition to describing existing programs, Appendix B describes proposed modifications (enhancements) to existing programs and proposed new programs and activities. Dominion expects no modifications to the plant facility.

3.4 Employment

Current Workforce

Dominion employs a permanent workforce for both Units 1 and 2 of approximately 879 employees and an additional 70 to 110 contract and matrixed employees at SPS; this is less than the range of 600 to 800 personnel per reactor unit estimated in the GEIS (Ref. 3.1-3, Section 2.3.8.1). Approximately 60 percent of the employees live in Isle of Wight, James City, or Surry Counties or the city of Newport News, with the balance of employees living in various other locations. Figure 3-2 shows the locations of these counties and Newport News.

Dominion refuels each SPS nuclear unit on a staggered 18-month schedule, which means at least one refueling every year and two refuelings every other year. During refueling outages, site employment increases above the 879 permanent workforce by as many as 700 workers for temporary (30 to 40 days) duty. This number is within the GEIS range of 200 to 900 additional workers per reactor outage.

License Renewal Increment

Performing the license renewal activities described in Section 3.3 would necessitate increasing SPS staff workload by some increment. The size of this increment would be a function of the schedule within which Dominion must accomplish the work and the amount of work involved.

The GEIS (Ref. 3.1-3, Section 2.6.2.7) assumes that NRC would renew a nuclear power plant license for a 20-year period, plus the duration remaining on the current license, and that NRC would issue the renewal approximately 10 years prior to license expiration. In other words, the renewed license would be in effect for approximately 30 years. The GEIS further assumes that the utility would initiate surveillance, monitoring, inspections, testing, trending and recordkeeping (SMITTR) activities at the time of issuance of the new license and would conduct license renewal SMITTR activities throughout the remaining 30-year life of the plant, sometimes during full-power operation (Ref. 3.1-3, Section B.3.1.3), but mostly during normal refueling and 10-year in-service refueling outages (Ref. 3.1-3, Table B.4).

Dominion has determined that the GEIS scheduling assumptions are reasonably representative of SPS incremental license renewal workload scheduling. Many SPS license renewal SMITTR activities would have to be performed during outages. Although some SPS license renewal SMITTR activities would be one-time efforts, others would be recurring periodic activities that would continue for the life of the plant.

The GEIS estimates that the most additional personnel needed to perform license renewal SMITTR activities would typically be 60 persons during a 10-year in-service refueling. Having established this upper value for what would be a single event in 20 years, the GEIS uses this number as the expected number of additional permanent workers needed per unit attributable to license renewal. GEIS Section C.3.1.2 uses this approach in order to "...provide a realistic upper bound to potential population-driven impacts…."

Dominion expects that existing "surge" capabilities for routine activities, such as outages, will enable Dominion to perform the increased SMITTR workload without adding SPS staff. For the purpose of performing its own analyses in this environmental report, Dominion is adopting the GEIS approach with one alteration. Plant modifications during license renewal would be SMITTR activities that would be performed mostly during outages, and Dominion would generally stagger SPS outage schedules so that both units would not be down at the same time. No plant facility modifications are anticipated. Therefore, Dominion believes it is unreasonable to assume that each unit would need an additional 60 workers. Instead, as a reasonably conservative high estimate, Dominion is assuming that SPS would require no more than a total of 60 additional permanent workers to perform all license renewal SMITTR activities.

Adding full-time employees to the plant workforce for the license renewal operating term would have the indirect effect of creating additional jobs and related population growth in the community. Dominion has used an employment multiplier appropriate to the Hampton Roads region (1.9), (Ref. 3.4-1) to calculate the total direct and indirect jobs in service industries that would be supported by the spending of the SPS workforce. The addition of 60 license renewal employees would generate approximately 54 indirect jobs distributed in the potentially impacted communities of Isle of Wight, James City, and Surry Counties and the City of Newport News. This number was calculated as follows: 60 (additional employees) × 1.9 (regional multiplier) = 114 (total employees). Of these, 60 would be direct employees and 54 would be indirect.

3.5 Gravel Neck Combustion Turbines Station

Gravel Neck Combustion Turbines Station operations do not affect Surry operations. However, SPS and Gravel Neck are permitted under the same groundwater withdrawal permit. To understand groundwater use at the site, one must consider both Surry and Gravel Neck groundwater withdrawal. The stations share a switchyard and transmission lines, and Gravel Neck operations are considered in the alternative analysis in Chapter 7. For these reasons, Dominion has chosen to include this section on the Gravel Neck Station.

Dominion operates the Gravel Neck Combustion Turbines Station on the SPS property (see Figure 2-2). Six simple-cycle turbines provide peaking power. Two Westinghouse units were constructed in 1970 and are rated at 15 megawatts (MW) and 25 MW. Four General Electric turbines were installed in 1988 and are each rated between 75 MW (summer) and 98 MW (winter). The Westinghouse turbines burn No. 2 fuel oil only. The four newer turbines can burn oil or natural gas. The turbines station shares the switchyard and the transmission lines leaving the switchyard with the nuclear units.

Oil and gas are delivered by pipeline from Newport News under the James River. The pipelines enter the Dominion property near the cooling water intake structure (see Figure 2-2). Fuel oil is stored in three tanks – one 320,000-gallon tank at the old units and two 3,177,000-gallon tanks associated with the new units – at the Combustion Turbines Station.

Three groundwater wells supply the potable and blowdown water needs for the turbines. These wells are included in the SPS site groundwater withdrawal permit (Section 3.1.2.2). Groundwater use at the Gravel Neck facility from 1992 through 1999, averaged 1,294,800 gallons per year (107,900 gallons per month or approximately 2.46 gpm) (Table 3-2). All potentially oil-contaminated stormwater runoff from Gravel Neck Combustion Turbines Station is pumped to the SPS settling basin that is permitted to discharge to the James River via the SPS discharge canal.

TABLES AND FIGURES

Table 3-1
SPS Groundwater Use

	Water Use (in Millions of Gallons)							
Month	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
January	14	11	9	9	12	8	9	12
February	13	10	7	7	8	8	9	9
March	12	9	10	10	8	8	11	13
April	11	9	10	7	8	9	11	10
May	11	10	10	8	7	6	10	8
June	11	9	11	8	9	10	12	12
July	12	10	9	9	10	8	11	11
August	11	10	11	8	9	8	12	7
September	11	10	8	7	9	10	11	9
October	11	8	8	11	7	8	11	10
November	11	10	9	13	8	10	12	9
December	10	9	11	7	8	10	11	9
Yearly Total	137	117	113	104	103	104	130	119
Monthly Average	11	10	9	9	9	9	11	10

Source: Ref. 3.1-13 to Ref. 3.1-20.

Notes:
1. Groundwater use data from wells: A (Low Level Intake); B (Condensate Tanks); C (Hi Level Road); D (Training Center); E (Warehouse Road); F (Recreation Facility); Const. Site (Construction Site).
2. All values in table have been rounded.

Table 3-2
Gravel Neck Combustion Turbines Station Groundwater Use

	Water Use (in Gallons)							
Month	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
January	1,400	900	1,000	900	1,900	600	500	800
February	1,500	900	1,100	1,200	1,100	600	5,800	241,400
March	3,100	1,400	2,200	1,700	2,000	600	1,600	161,600
April	3,100	1,400	900	1,900	2,900	1,000	618,400	700
May	1,900	800	1,000	1,700	2,600	115,200	0	99,200
June	2,600	1,400	2,900	1,300	700	484,700	0	1,100
July	1,900	2,100	2,300	1,100	100	531,900	427,700	1,244,100
August	1,100	1,600	1,800	2,000	100	314,700	1,077,500	1,609,000
September	1,200	1,700	800	1,500	7,600	187,100	1,065,300	711,000
October	1,400	1,200	2,700	1,400	1,300	186,600	1,005,300	86,800
November	1,100	1,100	700	2,300	700	289,200	531,400	700
December	1,400	1,100	1,300	1,000	400	700	800	1,700
Yearly Total	21,700	15,600	18,700	18,000	21,400	1,927,500	4,734,300[a]	4,158,100
Monthly Average	1,800	1,300	1,600	1,500	1,800	160,600	394,500	346,500

Source: Ref. 3.1-13 to Ref. 3.1-20.
Note: Groundwater use data is from wells G (old CT); H (Gravel Neck CT); and J (Gravel Neck). Increase in use between 1992-1996 and 1997-1999 reflects a change in procedures. Water is stored in a storage tank at Gravel Neck. Prior to 1997, the water was delivered by tanker truck; since 1997, groundwater has been used to fill the storage tank. The turbines station is a peaking facility, so power generation and water use are sporadic.
a. Equivalent to 9 gallons per minute.

Figure 3-1
Power Block Area for Surry Power Station Units 1 and 2

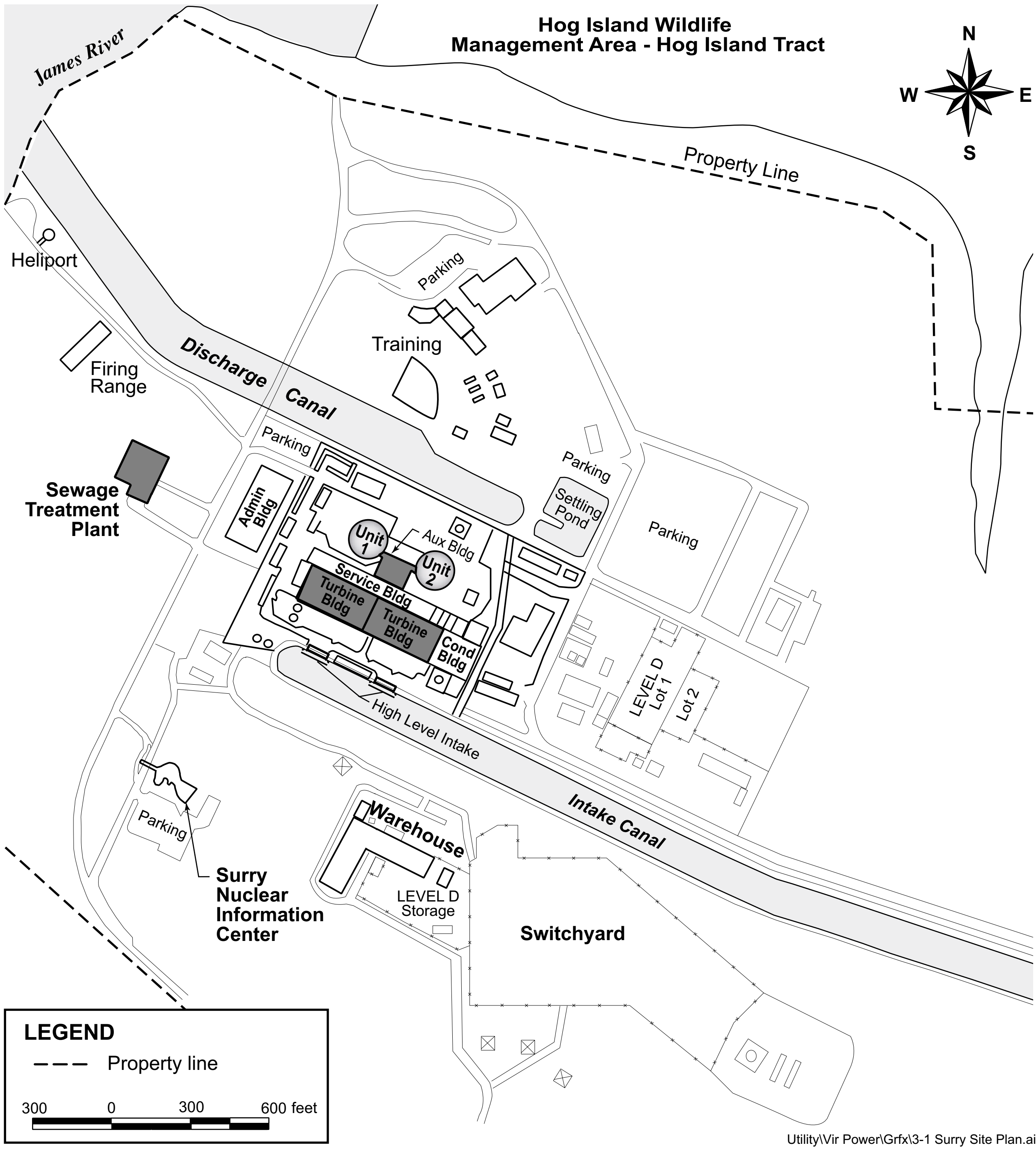


Figure 3-2
Eastern Virginia Groundwater Management Area

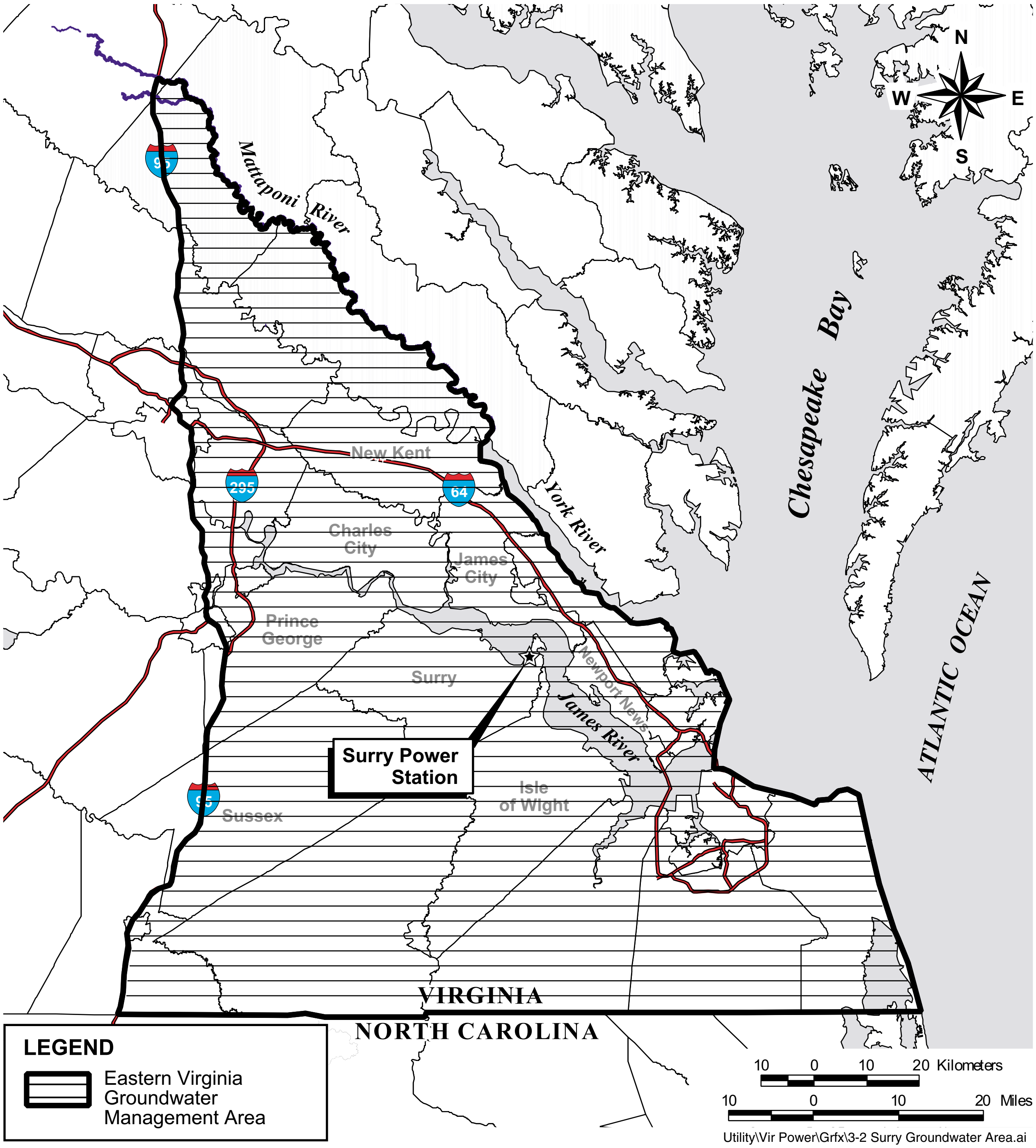
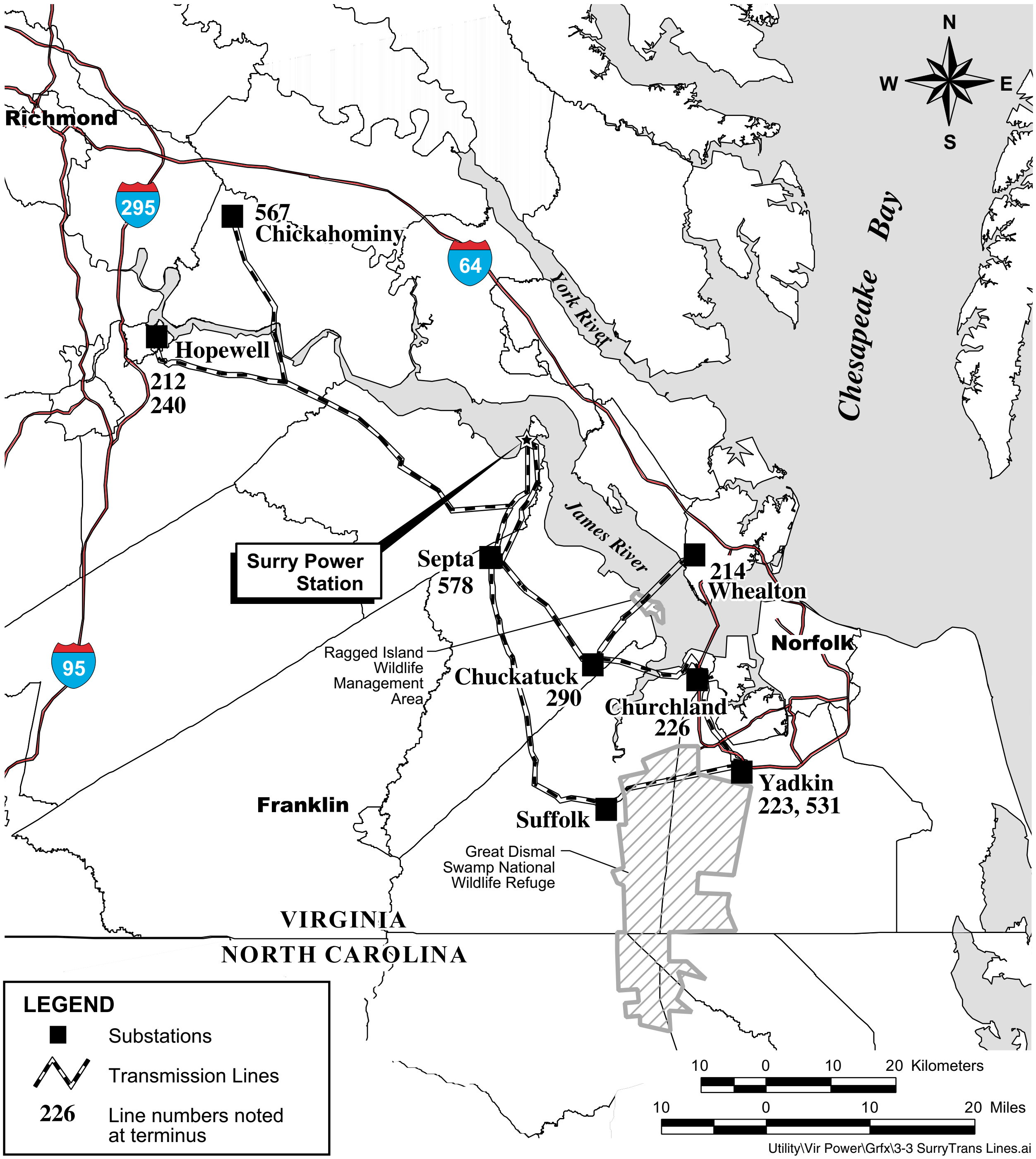


Figure 3-3
Transmission Corridors



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4.0 ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION AND MITIGATING ACTIONS

NRC Input

"The environmental report shall include an analysis that considers…the environmental effects of the proposed action…and alternatives available for reducing or avoiding adverse environmental effects." 10 CFR 51.53(c)

The environmental report shall discuss the "…impact of the proposed action on the environment. Impacts shall be discussed in proportion to their significance…." 10 CFR 51.45(b)(1) as adopted by 10 CFR 51.53(c)(2)

Chapter 4 presents an assessment of the environmental consequences and potential mitigating actions associated with the renewal of Surry Power Station's (SPS's) operating licenses. The U.S. Nuclear Regulatory Commission (NRC) has identified and analyzed 92 environmental issues that it considers to be associated with nuclear power plant license renewal and has designated the issues as Category 1, Category 2, or NA (not applicable), (Ref. 4.0-1). NRC has designated an issue as Category 1 if, after analysis, the following criteria were met:

- the environmental impacts associated with the issue have been determined to apply either to all plants or, for some issues, to plants having a specific type of cooling system or other specified plant or site characteristic;
- a single significance level (i.e., small, moderate, or large) has been assigned to the impacts that would occur at any plant, regardless of which plant is being evaluated (except for collective offsite radiological impacts from the fuel cycle and from high-level waste and spent-fuel disposal); and
- mitigation of adverse impacts associated with the issue has been considered in the analysis, and it has been determined that additional plant-specific mitigation measures are likely to be not sufficiently beneficial to warrant implementation.

Surry Power Station	
Category 1 issues not applicable[a]	18
Category 1 issues applicable	51
NA[b] issues	2
Category 2 issues not applicable	9
Category 2 issues applicable	12

a. Not applicable to Surry because they pertain to design or operational features that Surry does not have.
b. Categorization and impact definitions do not apply.

If the NRC analysis concluded that one or more of the Category 1 criteria could not be met, NRC designated the issue as Category 2. NRC requires plant-specific analysis for Category 2 issues. NRC designated two issues as NA, signifying that the categorization and impact definitions do not apply to these issues. NRC rules do not require analyses of Category 1 issues that NRC has resolved using the generic findings (10 CFR 51, Appendix B, Table B-1) in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS), (Ref. 4.0-1). An applicant may reference the generic findings or GEIS analyses for Category 1 issues. Appendix A lists the 92 issues and identifies the Environmental Report section that addresses each issue.

Category 1 License Renewal Issues

NRC Input

"…The environmental report for the operating license renewal stage is not required to contain analyses of the environmental impacts of the license renewal issues identified as Category 1 issues in Appendix B to subpart A of this part." 10 CFR 51.53(c)(3)(i)

"…[A]bsent new and significant information, the analysis for certain impacts codified by this rulemaking need only be incorporated by reference in an applicant's environmental report for license renewal…." Discussion of Regulatory Requirements, (Ref. 4.0-2; pg. 28483)

Dominion has determined that, of the 69 Category 1 issues, 11 do not apply to SPS because they apply to design or operational features that are not relevant to SPS. These are: groundwater withdrawal rates of less than 100 gallons per minute and heat dissipation by discharge to a lake or groundwater, cooling towers, or cooling ponds. In addition, because Dominion does not plan to conduct any refurbishment activities, the NRC findings for the seven Category 1 issues that apply only to refurbishment clearly overstate SPS refurbishment impacts and do not apply. Table 4-1 lists these 18 issues and expands on Dominion's basis for determining that they are not applicable to SPS.

Table 4-2 lists the 51 Category 1 issues that Dominion has determined to be applicable to SPS and also lists the two issues for which NRC came to no generic conclusion (NA; Issues 60 and 92). The table includes findings that NRC codified and references their supporting GEIS analyses. Dominion has reviewed the NRC findings and identified no new and significant information, nor has Dominion become aware of any information that would make the NRC findings inapplicable to SPS. Therefore, Dominion adopts by reference the NRC findings for these Category 1 issues.

Category 2 License Renewal Issues

NRC Input

"...The environmental report must contain analyses of the environmental impacts of the proposed action, including the impacts of refurbishment activities, if any, associated with license renewal and the impacts of operation during the renewal term, for those issues identified as Category 2 issues in Appendix B to subpart A of this part...." 10 CFR 51.53(c)(3)(ii)

"The report must contain a consideration of alternatives for reducing adverse impacts, as required by § 51.45(c), for all Category 2 license renewal issues...." 10 CFR 51.53(c)(3)(iii)

NRC designated 21 issues as Category 2. Sections 4.1 through 4.20 address each of the Category 2 issues, beginning with a statement of the issue. As with the Category 1 issues, some Category 2 issues (five) apply to design or operational features that SPS does not have. In addition, some Category 2 issues (four) apply only to refurbishment activities. If the issue does not apply to SPS, the section explains the basis for inapplicability.

For the 12 Category 2 issues that Dominion has determined to be applicable to SPS, the sections contain required analyses. These analyses include conclusions regarding the significance of the impacts relative to renewal of the operating licenses for SPS and discuss potential mitigative alternatives, when applicable, and to the extent required. Dominion has identified the significance of the impacts associated with each issue as either small, moderate, or large, consistent with the criteria that NRC established in 10 CFR 51, Appendix B, Table B-1, Footnote 3 as follows:

Small - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.

Moderate - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.

Large - Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

In accordance with National Environmental Policy Act (NEPA) practice, Dominion considered ongoing and potential additional mitigation in proportion to the significance of the impact to be addressed (e.g., impacts that are small receive less mitigative consideration than impacts that are large).

NA License Renewal Issues

NRC determined that its categorization and impact finding definitions did not apply (NA = not applicable) to Issues 60 and 92. Dominion included these issues in Table 4-2. NRC noted that applicants currently do not need to submit information on chronic effects from electromagnetic fields (10 CFR 51, Appendix B, Table B-1, Footnote 5). For the other NA issue, environmental justice, NRC did not require information from applicants, but noted that it will be addressed in individual license renewal reviews (10 CFR 51, Appendix B, Table B-1, Footnote 6). Dominion has included environmental justice demographic information in Section 2.11.

4.1 Water Use Conflicts (Plants with Cooling Ponds or Cooling Towers Using Makeup Water from a Small River with Low Flow)

NRC Input

"... If the applicant's plant utilizes cooling towers or cooling ponds and withdraws makeup water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on the flow of the river and related impacts on instream and riparian ecological communities must be provided. The applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow." 10 CFR 51.53(3)(ii)(A)

"The issue has been a concern at nuclear power plants with cooling ponds and at plants with cooling towers. Impacts on instream and riparian communities near these plants could be of moderate significance in some situations." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 13

The issue of water use conflicts does not apply to SPS because the plant does not use cooling ponds or cooling towers. As Section 3.1.2 describes, SPS uses a once-through cooling system.

4.2 Entrainment of Fish and Shellfish in Early Life Stages

NRC Input

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations…or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from…entrainment." 10 CFR 51.53(c)(3)(ii)(B)

"...The impacts of entrainment are small in early life stages at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. Further, ongoing efforts in the vicinity of these plants to restore fish populations may increase the numbers of fish susceptible to intake effects during the license renewal period, such that entrainment studies conducted in support of the original license may no longer be valid..." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 25

NRC made impacts on fish and shellfish resources resulting from entrainment a Category 2 issue because it could not assign a single significance level (small, moderate, or large) to the issue. The impacts of entrainment are small at many facilities, but they may be moderate or large at others. Also, ongoing restoration efforts may increase the number of fish susceptible to intake effects during the license renewal period (Ref. 4.0-1, Section 4.2.2.1.2). Information to be ascertained includes (1) type of cooling system (whether once-through or cooling pond) and (2) current Clean Water Act (CWA) 316(b) determination or equivalent state documentation.

As Section 3.1.2 describes, SPS has a once-through heat dissipation system. As described below, Dominion has state documentation equivalent to a CWA 316(b) determination.

Section 316(b) of the CWA requires that any standard established pursuant to Sections 301 or 306 of the CWA shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts (33 USC 1326). Entrainment through the condenser cooling system of fish and shellfish in the early life stages is one of the adverse environmental impacts that the best technology available minimizes. Virginia State Water Control Board regulations provide that compliance with a Virginia Pollutant Discharge Elimination System (VPDES) permit constitutes compliance with Sections 301 and 306 of the CWA (Ref. 4.2-1). In response to Board requirements, Dominion submitted a CWA Section 316(b) demonstration for SPS on November 1, 1980 (Ref. 4.2-2). Appendix B includes a copy of the title page of the current SPS VPDES permit. Issuance of the SPS VPDES permit indicates the Board's conclusion that SPS, in operating in conformance with the permit, would be in compliance with the CWA requirements. Dominion concludes that the Commonwealth regulation and the SPS VPDES permit constitute the SPS CWA 316(b) determination. Dominion also concludes that any environmental impact from entrainment of fish and shellfish in early life stages is small and does not require further mitigation.

4.3 Impingement of Fish and Shellfish

NRC Input

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations…or equivalent State permits and supporting documentation. If the applicant can not provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from…impingement…."10 CFR 51.53(c)(3)(ii)(B)

"…The impacts of impingement are small at many plants, but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 26

NRC made impacts on fish and shellfish resources resulting from impingement a Category 2 issue because it could not assign a single significance level to the issue. Impingement impacts are small at many facilities, but might be moderate or large at others (Ref. 4.0-1, Section 4.2.2.1.3). Information to be ascertained includes: (1) type of cooling system (whether once-through or cooling pond), and (2) current CWA 316(b) determination or equivalent state documentation.

As Section 3.1.2 describes, SPS has a once-through heat dissipation system. Section 4.2 discusses the CWA 316(b) determination for SPS, indicating compliance with the use of the best available technology. Impingement of fish and shellfish on the intake screens is one of the adverse impacts that the best technology available minimizes.

Dominion concludes that this environmental impact is small and does not require further mitigation.

4.4 Heat Shock

NRC Input

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act… 316(a) variance in accordance with 40 CFR 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock …." 10 CFR 51.53(c)(3)(ii)(B)

"…Because of continuing concerns about heat shock and the possible need to modify thermal discharges in response to changing environmental conditions, the impacts may be of moderate or large significance at some plants…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 27

NRC made impacts on fish and shellfish resources resulting from heat shock a Category 2 issue because of continuing concerns about thermal discharge effects and the possible need to modify thermal discharges in the future in response to changing environmental conditions (Ref. 4.0-1, Section 4.2.2.1.4) Information to be ascertained includes: (1) type of cooling system (whether once-through or cooling pond), and (2) evidence of a CWA 316(a) variance or equivalent state documentation.

As Section 3.1.2 describes, SPS has a once-through heat dissipation system. As discussed below, Dominion has a CWA 316(a) variance for SPS discharges.

Section 316(a) of the CWA establishes a process whereby a thermal effluent discharger can demonstrate that thermal discharge limitations are more stringent than necessary and, using a variance, obtain alternative facility-specific thermal discharge limits (33 USC 1326). Dominion submitted a CWA Section 316(a) Demonstration for SPS to the Virginia State Water Control Board on September 1, 1977 (Ref. 4.4-1). Part I.C.16 of the current SPS VPDES permit (Appendix B) refers to this submittal, indicating that effluent limitations more stringent than the thermal limitations included in the permit are not necessary to assure the protection and propagation of a balanced indigenous community of shellfish, fish, and wildlife in the James River. The fact sheet that accompanies the permit provides the justification for the variance (Ref. 4.4-2, Section 21).

Dominion concludes thta impacts from heat shock are small and no mitigtaion is warranted.

4.5 Groundwater Use Conflicts (Plants that Use > 100 gpm)

NRC Input

"If the applicant's plant...pumps more than 100 gallons (total onsite) of groundwater per minute, an assessment of the impact of the proposed action on groundwater use must be provided." 10 CFR 51.53(c)(3)(ii)(C)

"Plants that use more than 100 gpm may cause groundwater use conflicts with nearby groundwater users." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 33

NRC made groundwater use conflicts a Category 2 issue because it could not assign a single significance level (small, moderate, or large) to the issue and because, if there were moderate or large impacts, mitigation might be warranted. The effect of groundwater use on neighboring groundwater users would depend on the rate of withdrawal and the distance to neighboring wells (Ref. 4.0-1, Section 4.8.1.1). Therefore, information to be ascertained includes: (1) SPS groundwater withdrawal rate (whether greater than 100 gpm), (2) distance to neighboring well(s), and (3) impact on the neighboring well(s).

As described in Section 3.1.2.2 and illustrated in Table 3-2, SPS used an average of 221 gallons per minute (gpm) of groundwater from 1992 through 1999; thus, this issue is applicable to SPS. The closest wells to the site are 1.0 miles north of the site boundary at the wildlife management area and 0.6 mile southwest of the site at a Drewry Point vacation cottage. Because the purpose of these wells is to supply domestic water for use at a wildlife management area and a vacation cottage, the water demand at each location should be minimal. The combined SPS/Gravel Neck combustion turbines facilities are permitted to remove groundwater at a rate of 294 gpm (Ref. 4.5-1). The onsite wells capable of the greatest yield are wells B, C, and E (Refs. 4.5-2 to 4.5-9). Well B is the one most used for production purposes and is the closest to the center of the SPS property. Data from well B were used to calculate the drawdown created by well E and the Construction Site Well. Using the data from well B, the well with the greatest yields, introduces additional conservatism in the calculations. Drawdown for well E and the Construction Site Well would not be as extensive as for well B. Well E is closest to Drewry Point, and the Construction Site Well is closest to the Hog Island Wildlife Management Area.

No pump tests have been performed on the site wells, other than specific capacity tests performed after well installation to determine maximum well yields. Therefore, in order to determine potential offsite impacts, two different kinds of well data and a computer model were used. The well data in Table 4-3 were collected from various sources (Refs. 4.5-10; 4.5-11 and 4.5-12) to supplement the data from the specific capacity test performed on well B. Data were assigned to the model, based on several assumptions. An average transmissivity for the area was used in the calculations, while a small storage coefficient within the accepted range for a confined aquifer was used. The data were input into a computer program containing the Theis equation. The drawdown was then calculated at the property boundary and the offsite well locations.

The Construction Site Well is located approximately 4,200 feet (0.6 mile plus 1,050 feet from the Construction Site Well to the property boundary) from the wildlife management area well. Well E is located approximately 1.23 miles (1 mile from the offsite well to the property boundary plus 1,200 feet to well E) from the Drewry Point cottage.

Based on the conservative pumping rate of the permitted withdrawal amount of 294 gpm (conservative because no site well is capable of pumping at that rate) at the Construction Site Well, the drawdown at the property boundary to the north is less than 3.8 feet. The projected drawdown at the wildlife management area well (4,200 feet from the Construction Site Well) would be less than 1.4 feet. The conservative pumping rate used in the model is higher than the highest annual average withdrawal rate from 1992 to 1999. The 8-year withdrawal average from 1992 to 1999 for wells at the SPS facility is approximately 221 gpm. A pumping rate of 220 gpm at the Construction Site Well would result in a drawdown of the potentiometric surface of approximately 2.8 feet at the property boundary and less than 1 foot at 4,200 feet from the Construction Site Well. The maximum yield of any SPS well is 220 gpm.

Based on the conservative pumping rate of 294 gpm at well E, the drawdown at the property boundary to the southwest is approximately 3.5 feet. The projected drawdown at the Drewry Point cottage (1.2 miles from well E) would be less than 0.5 feet. The 8-year withdrawal average from 1992 to 1999 from wells at the SPS facility is approximately 221 gpm. The drawdown at the property boundary, based on a rate of 220 gpm, would be approximately 2.8 feet. The drawdown at the offsite well would be approximately 0.5 feet.

The SPS facility is located in an area isolated by the James River, the Hog Island Wildlife Management Area to the north and south, and the Chippokes Plantation State Park to the southwest. The remoteness of the facility ensures both limited development in the area and limited use of groundwater as a source of water. The offsite wells are located in fairly remote areas and are capable of relatively small yields (35 gpm). The small amount of projected drawdown at the two closest offsite locations would not significantly impact these wells. Therefore, the impact to groundwater resources in the area would be small and mitigation is not warranted.

4.6 Groundwater Use Conflicts (Plants Using Cooling Towers Withdrawing Makeup Water from a Small River)

NRC Input

"... If the applicant's plant utilizes cooling towers or cooling ponds and withdraws makeup water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year.... [The] applicant shall also provide an assessment of the impact of the withdrawal of water from the river on alluvial aquifers during low flow." 10 CFR 51.53(c)(3)(ii)(A)

"Water use conflicts may result from surface water withdrawals from small water bodies during low flow conditions which may affect aquifer recharge, especially if other groundwater or upstream surface water users come on line before the time of license renewal." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 34

The issue of groundwater use conflicts does not apply to SPS because the plant does not use cooling towers or cooling ponds. As Section 3.1.2 describes, SPS uses a once-through cooling system.

4.7 Groundwater Use Conflicts (Plants Using Ranney Wells)

NRC Input

"…If the applicant's plant uses Ranney wells…an assessment of the impact of the proposed action on groundwater use must be provided…." 10 CFR 51.53(c)(3)(ii)(C)

"… Ranney wells can result in potential groundwater depression beyond the site boundary. Impacts of large groundwater withdrawal for cooling tower makeup at nuclear power plants using Ranney wells must be evaluated at the time of application for license renewal…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 35

The issue of groundwater use conflicts does not apply to SPS because the plant does not use Ranney wells. As Section 3.1.2 describes, SPS uses a once-through cooling system.

4.8 Degradation of Groundwater Quality

NRC Input

"...If the applicant's plant is located at an inland site and utilizes cooling ponds...an assessment of the impact of the proposed action on groundwater quality must be provided...." 10 CFR 51.53(c)(3)(ii)(D)

"...Sites with closed cycle cooling ponds may degrade groundwater quality. For plants located inland, the quality of the groundwater in the vicinity of the ponds must be shown to be adequate to allow continuation of current uses...." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 39

The issue of groundwater degradation does not apply to SPS because the plant does not use cooling ponds. As Section 3.1.2 describes, SPS uses a once-through cooling system.

4.9 Impacts of Refurbishment on Terrestrial Resources

NRC Input

The environmental report must contain an assessment of "…the impacts of refurbishment and other license renewal-related construction activities on important plant and animal habitats…." 10 CFR 51.53(c)(3)(ii)(E)

"…Refurbishment impacts are insignificant if no loss of important plant and animal habitat occurs. However, it cannot be known whether important plant and animal communities may be affected until the specific proposal is presented with the license renewal application…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 40

"…If no important resources would be affected, the impacts would be considered minor and of small significance. If important resources could be affected by refurbishment activities, the impacts would be potentially significant…." Ref. 4.0-1, Section 3.6, pg. 3-6

NRC made impacts to terrestrial resources from refurbishment a Category 2 issue because the significance of ecological impacts cannot be determined without considering site- and project-specific details (Ref. 4.0-1, Section 3.6). Aspects of the site project to be ascertained are: (1) the identification of important ecological resources; (2) the nature of refurbishment activities; and (3) the extent of impact to plant and animal habitats.

The issue of impacts of refurbishment on terrestrial resources is not applicable to SPS because, as discussed in Section 3.2, Dominion has no plans for refurbishment or other license-renewal-related construction activities at SPS.

4.10 Threatened or Endangered Species

NRC Input

"Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act." 10 CFR 51.53(c)(3)(ii)(E)

"Generally, plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. However, consultation with appropriate agencies would be needed at the time of license renewal to determine whether threatened or endangered species are present and whether they would be adversely affected." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 49

NRC made impacts to threatened and endangered species a Category 2 issue because the status of many species is being reviewed; site-specific assessment is required to determine whether any identified species could be affected by refurbishment activities or continued facility operations through the renewal period. In addition, compliance with the Endangered Species Act requires consultation with the appropriate federal agency (Ref. 4.0-1, Sections 3.9 and 4.1).

Section 2.2 of this Environmental Report describes aquatic communities of the lower James River in the vicinity of SPS. Section 2.4 discusses ecological habitats at SPS and along associated transmission lines. Section 2.5 discusses terrestrial and aquatic species that occur or may occur at SPS and along associated transmission lines, and that have special status (i.e., Federal or State threatened or endangered).

With the exception of the bald eagle, Dominion is not aware of any endangered or threatened terrestrial species at SPS or along the associated transmission lines. Current operations of SPS and transmission line maintenance procedures do not adversely affect any terrestrial habitat (see Section 2.4). Furthermore, plant operations and transmission line maintenance procedures are not expected to significantly change during the license renewal period. Therefore, no adverse impacts to endangered or threatened terrestrial species from current or future operations of SPS are expected. In addition, as discussed in Section 3.2, Dominion has no plans to conduct refurbishment or construction activities at SPS during the license renewal period. Therefore, there would be no refurbishment-related impacts to endangered or threatened terrestrial species, and no further analysis of refurbishment- related impacts is applicable.

As part of its Clean Water Act Section 316(b) Demonstration, Dominion conducted extensive surveys of fish in the lower James River in the vicinity of SPS over a 9-year period (1970-1978). No Federally listed species were collected in these surveys (see Section 2.5). Small numbers of Atlantic sturgeon (currently a candidate for Federal listing) were collected in monthly otter trawl samples designed to characterize the fish populations of the "shelf" zone, the area adjacent to the main channel of the James River near SPS (Ref. 4.2-2, Tables 11 and 12). No Atlantic sturgeon were observed in screenwash samples collected during a 1974-1978 study of impingement at SPS (Ref. 4.2-2, Tables 22 and 23) and none have been observed in screenwash collections since 1978. The likelihood of Atlantic sturgeon being impinged at the SPS intakes over the license renewal term is very low, because they are strong swimmers as adults and prefer deeper, main-channel waters. Based on the Section 316(b) Demonstration and subsequent operating experience, this species is not especially vulnerable to impingement at SPS. Further, the Ristroph travelling screens at SPS minimize impingement mortality, with survival rates higher than 90 percent for most species (Ref. 4.2-2, pg. 85).

No Atlantic sturgeon eggs or larvae were collected in a 1976-1978 study of entrainment at SPS (Ref. 4.2-2, Table 26). It is conceivable that small numbers of Atlantic sturgeon eggs and/or larvae could be entrained over the license renewal term. However, given the spawning habitat preferences and reproductive biology of the species, the likelihood is small. Atlantic sturgeon ascend rivers along the Atlantic coast to spawn in fresh water, generally between the freshwater-salt water interface and the Fall Line. Sturgeon spawn in the main channel of large rivers like the James, frequently at bends in the river where the current is strong and the substrate is hard-packed and swept clean of silt. Because sturgeon eggs are demersal (heavier than water) and adhesive, they are not likely to float downstream and into the intakes of SPS. Sturgeon eggs tend to sink to the bottom of river channels and adhere to rocks, logs, and submerged aquatic vegetation. Based on the 316(b) Demonstration and the biology of the species, the Atlantic sturgeon is not especially vulnerable to entrainment at SPS. Any impacts to Atlantic sturgeon from entrainment would be small, and would be at the level of the individual egg or larvae rather than the population.

Dominion has limited its evaluation of potential impacts to threatened or endangered aquatic species to those that might be present in the James River in the vicinity of SPS and that could be affected by withdrawal or discharge of James River water used for condenser cooling. Other threatened or endangered aquatic species might be present in water bodies (streams, ponds, and wetlands) crossed by SPS transmission line corridors. However, Dominion is planning no refurbishment or other license-renewal-related construction activities and is not aware of any SPS operational or maintenance practices that could affect aquatic species in these water bodies. Therefore, consistent with 10 CFR 51, Dominion has identified threatened and endangered species that might be present in transmission corridor water bodies (Section 2.5), but assumes that any such species would not be affected by continued operation of SPS through the license renewal period.

Dominion has corresponded with the U.S. Fish and Wildlife Service, National Marine Fisheries Service, and Virginia Department of Game & Inland Fisheries. See Section 9.1.2 for discussion of threatened and endangered species consultation and Appendix C for correspondence.

4.11 Air Quality During Refurbishment

NRC Input

"...If the applicant's plant is located in or near a nonattainment or maintenance area, an assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce must be provided in accordance with the Clean Air Act as amended...." 10 CFR 51.53(c)(3)(ii)(F)

"...Air quality impacts from plant refurbishment associated with license renewal are expected to be small. However, vehicle exhaust emissions could be cause for concern at locations in or near nonattainment or maintenance areas. The significance of the potential impact cannot be determined without considering the compliance status of each site and the numbers of workers expected to be employed during the outage...." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 50

NRC made impacts to air quality during refurbishment a Category 2 issue because vehicle exhaust emissions could be cause for some concern; a general conclusion about the significance of the potential impact could not be drawn without considering the compliance status of each site and the number of workers expected to be employed during the outage (Ref. 4.0-1, Section 3.3). Information needed would include: (1) the attainment status of the plant-site area, and (2) the number of additional vehicles as a result of refurbishment activities.

Air quality during refurbishment is not applicable to SPS because, as discussed in Section 3.2, Dominion has no plans for refurbishment at SPS.

4.12 Microbiological Organisms

NRC Input

"If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river having an annual average flow of less than 3.15 × 10^{12}ft^3/year (9 × 10^{10}m^3/year), an assessment of the proposed action on public health from thermophilic organisms in the affected water must be provided." 10 CFR 51.53(c)(3)(ii)(G)

"These organisms are not expected to be a problem at most operating plants except possibly at plants using cooling ponds, lakes, or canals that discharge to small rivers. Without site-specific data, it is not possible to predict the effects generically." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 57

NRC designated impacts on public health from thermophilic organisms a Category 2 issue, because NRC did not have sufficient data available for facilities using cooling ponds, lakes, or canals that discharge to small rivers. Information to be determined includes: (1) whether the plant discharges to a small river, and (2) whether discharge characteristics (particularly temperature) are conducive to the survival of thermophilic organisms in public waters.

This issue is not applicable to SPS because SPS discharges to the James River, which at the location of SPS, is categorized as an estuary (Ref. 4.0-1, Table 5-13).

4.13 Electric Shock from Transmission-Line-Induced Currents

NRC Input

The environmental report must contain an assessment of the impact of the proposed action on the potential shock hazard from transmission lines "...[i]f the applicant's transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced currents." 10 CFR 51.53(c)(3)(ii)(H)

"Electrical shock resulting from direct access to energized conductors or from induced charges in metallic structures have not been found to be a problem at most operating plants and generally are not expected to be a problem during the license renewal term. However, site-specific review is required to determine the significance of the electric shock potential at the site." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 59

NRC made impacts of electric shock from transmission lines a Category 2 issue, because without a review of each plant's transmission line conformance with the National Electrical Safety Code® (NESC®) (Ref. 4.13-1) criteria, NRC could not determine the significance of the electric shock potential. The GEIS states that the transmission lines of concern are those between the plant switchyard and its connection with the existing transmission system (Ref. 4.0-1, Section 4.5, pg. 4-59).

Information to be ascertained includes: (1) change in line use and voltage since last analysis, (2) conformance with NESC® standards, and (3) potential change in land use along transmission lines since initial NEPA review. No NRC or NEPA analysis has been conducted of the SPS transmission lines' induced current hazard (although induced current was considered when the lines were designed). Therefore, this section addresses only the second analytical element: conformance with NESC® standards.

Objects located near transmission lines can become electrically charged due to the effect of what is commonly called "static electricity," but is more precisely termed "an electrostatic field." This charge results in a current that flows through the object to the ground. The current is called "induced" because there is no direct connection between the line and the object. The induced current can also flow to the ground through the body of a person who touches the object. An object that is particularly well insulated from the ground, such as a car on rubber tires, can actually store an electrical charge, becoming what is called "capacitively charged." A person standing on the ground and touching the car receives an electric shock due to the sudden discharge of the capacitive charge through the person's body to the ground. The intensity of the shock depends on several factors, including:

- the strength of the electrostatic field which, in turn, depends on the voltage of the transmission line

- the height of the line above the ground
- the size of the object on the ground.

In 1977, the NESC® adopted a provision that describes how to establish minimum vertical clearances to the ground for electric lines having voltages exceeding 98 kilovolt (kV) alternating current to ground[1]. The clearance must limit the induced current[2] due to electrostatic effects to 5 milliamperes if the largest anticipated truck, vehicle, or equipment were short-circuited to ground. The NESC® chose this limit as being protective of the health of a person who wears a heart pacemaker. By way of comparison, the setting of ground fault circuit interrupters used in residential wiring (special breakers for outside circuits or those with outlets around water pipes) is 6 milliamperes; the shock that one feels on a dry day after walking on a carpet or sliding across a car seat and touching an object is the result of approximately 3 milliamperes of current.

As described in Section 3.1.3, there are six 230-kV lines and three 500-kV lines that distribute power from SPS to the Dominion grid. These nine lines were installed between 1960 and 1972, before the 5-milliampere provision was first introduced into the NESC® in 1977. In addition, there are two 230-kV lines completely on SPS property that send power from the combustion turbines at Gravel Neck to the SPS switchyard. This analysis does not include the Gravel Neck lines, because their operation is independent of SPS operation.

Dominion's analysis of the transmission lines first identified the limiting case for each of the nine transmission lines. The limiting case is the configuration along each transmission line where the potential for current-induced shock would be greatest. Finding the limiting-case configuration involved two considerations. First, Dominion minimized the amount of right-of-way required by running the various lines along the same rights-of-way wherever possible, including using the rights-of-way used by lines from other plants. The existence of multiple SPS lines at one place could cause a location with otherwise less potential for shock to become the limiting case. Second, the various lines use a variety of tower designs, resulting in different ground clearances along a given line. Therefore, it became necessary for Dominion to examine ground clearance and multiple lines to determine the limiting case. Once the case was identified, Dominion calculated the electrostatic field strength for each transmission line, and then calculated the induced current, as described below.

Dominion calculated field strength and induced current using a computer code called ENG01814. This code was developed by Cincinnati Gas & Electric Company and has been used at Dominion since 1978. The results of this computer program have been field-verified

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1. Part 2, Rules 232C1c and 232D3c.
2. The NESC® and the GEIS use the phrase "steady-state current," whereas 10 CFR 51.53(c)(3)(ii)(H) uses the phrase "induced current." The phrases mean the same here.

through actual electric field measurements under energized transmission lines. The input parameters for this code included the design features of the limiting-case scenario for each transmission line, the NESC® requirement that line sag be determined at 120°F conductor temperature, and the maximum vehicle size under the lines as a tractor-trailer 55 feet long, 8.2 feet wide, and an average of 11.8 feet high. Dominion calculated the 120°F clearance based on design clearances.

The analysis determined that four of the nine transmission lines have the capacity to induce enough charge in a vehicle parked beneath the lines to result in as much as 5.068 milliamperes of short-circuit discharge current. Although these lines marginally exceed the NESC® limit, all the SPS transmission lines were installed prior to the requirements of the 1977 edition of the NESC®. Therefore, the provisions of the NESC® for preventing electric shock from induced current are not applicable. The results for each transmission line are provided in Table 4-4.

Given the very slight (about 1 percent) exceedance of the NESC® limit and the industry-standard 6-milliampere setting of ground fault circuit interrupters, Dominion's assessment under 10 CFR 51 concludes that electric shock is of small significance for the SPS transmission lines. This conclusion would remain valid into the future if there are no changes in line use, voltage, current, and maintenance practices and no changes in land use under the lines – conditions over which Dominion has control. Dominion surveillance and maintenance procedures (see Section 3.1.3) provide assurance that design ground clearances will not change. Due to the small significance of the issue, mitigation measures are not warranted.

4.14 Housing Impacts

NRC Input

The environmental report must contain "...[a]n assessment of the impact of the proposed action on housing availability…" 10 CFR 51.53(c)(3)(ii)(I)

"Housing impacts are expected to be of small significance at plants located in a medium or high population area and not in an area where growth control measures that limit housing development are in effect. Moderate or large housing impacts of the workforce associated with refurbishment may be associated with plants located in sparsely populated areas or areas with growth control measures that limit housing development." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 63

"...[S]mall impacts result when no discernible change in housing availability occurs, changes in rental rates and housing values are similar to those occurring statewide, and no housing construction or conversion occurs." Ref. 4.0-1, Section 4.7.1.1

NRC made housing impacts a Category 2 issue, because impact magnitude depends on local conditions that the NRC could not predict for all plants at the time of GEIS publication (Ref. 4.0-1, Section 3.7.2). Local conditions to be ascertained are: (1) population categorization as low, medium, or high, and (2) applicability of growth control measures.

Refurbishment activities and continued operations could result in housing impacts due to increased staffing. As described in Section 3.2, Dominion does not plan to perform refurbishment. Dominion concludes that there would be no refurbishment-related impacts to area housing and no analysis is therefore required. Accordingly, the following discussion focuses on impacts of continued operations on local housing availability.

As described in Section 2.6, SPS is located in a high population area. As noted in Section 2.9, the area of interest is not subject to growth control measures that limit housing development. In 10 CFR 51, Subpart A, Appendix B, Table B-1, NRC concluded that impacts to housing are expected to be of small significance at plants located in "high" population areas where growth control measures are not in effect. Therefore, Dominion expects housing impacts to be small.

This conclusion is supported by the following site-specific housing analysis. The maximum impact to area housing is calculated using the following assumptions: (1) all direct and indirect jobs would be filled by in-migrating residents; (2) the residential distribution of new residents would be similar to current worker distribution; and (3) each new job created (direct and indirect) represents one housing unit. As described in Section 3.4, approximately 60 percent of the SPS employees reside in Isle of Wight, James City, and Surry Counties or the City of Newport News. Therefore, the focus of the housing impact analysis is on these areas. As also discussed in Section 3.4, Dominion's conservative estimate of 60 license renewal employees could generate the demand for 114 housing units (60 direct and 54 indirect jobs). If it is assumed that 60 percent of the 114 new workers would locate in the four areas, consistent with current employee trends, approximately 68 housing units would be required in Newport News and Isle of Wight, James City, and Surry Counties. In an area which has a population of more than 1.5 million, this demand would not create a discernible change in housing availability, rental rates or housing values, or spur housing construction or conversion. Dominion concludes that impacts to housing availability resulting from plant-related population growth would be small and would not warrant mitigation.

4.15 Public Utilities: Public Water Supply Availability

NRC Input

The environmental report must contain "...an assessment of the impact of population increases attributable to the proposed project on the public water supply." 10 CFR 51.53(c)(3)(ii)(I)

"An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 65

"Impacts on public utility services are considered small if little or no change occurs in the ability to respond to the level of demand and thus there is no need to add capital facilities. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs. Impacts are considered large if existing service levels (such as quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services." Ref. 4.0-1, Section 3.7.4.5

NRC made public utility impacts a Category 2 issue because an increased problem with water availability, resulting from pre-existing water shortages, could occur in conjunction with plant demand and plant-related population growth (Ref. 4.0-1, Section 4.7.3.5). Local information needed would include: (1) a description of water shortages experienced in the area, and (2) an assessment of the public water supply system's available capacity.

The NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demands on local water resources. Section 3.4 describes potential population increases, and Section 2.6 describes the distribution of that population in the area associated with license renewal activities at SPS. Section 2.10.1 describes the public water supply systems potentially affected by license renewal activities, their permitted capacities, and current demands. SPS does not use water from a municipal system; therefore, Dominion does not expect SPS to have an effect on local water supplies. As discussed in Section 3.2, no refurbishment is planned for SPS and no refurbishment impacts are therefore expected.

The impact to the local water supply systems resulting from plant-related population growth can be determined by calculating the amount of water that would be required by these individuals. The average American uses between 50 and 80 gallons per day for personal use (Ref. 4.15-1, pg. 2). As described in Section 3.4, Dominion's conservative estimate of 60 license renewal employees could generate a total of 114 new jobs, which could result in a population increase of 307 in the area (114 jobs multiplied by 2.69, which is the average number of persons per household in the area [Ref. 4.15-2]). Using this consumption rate, the plant-related population increase would require an additional 24,560 gallons per day (307 people multiplied by 80 gallons per day). If it is assumed that this increase is distributed across the four potentially affected communities, consistent with current employee trends, the increase in water demand would represent an insignificant percentage of capacity for the water supply systems in these communities. (See Section 2.10.1 for a discussion of the current capacities of these systems.) Dominion concludes that impacts resulting from plant-related population growth to public water supplies would be small, requiring no additional capacity and not warranting mitigation.

4.16 Education Impacts from Refurbishment

NRC Input

The environmental report must contain "…an assessment of the impact of the proposed action on... public schools (impacts from refurbishment activities only) within the vicinity of the plant…." 10 CFR 51.53(c)(3)(ii)(I)

"…Most sites would experience impacts of small significance, but larger impacts are possible depending on site- and project-specific factors…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 66

"…[S]mall impacts are associated with project-related enrollment increases of 3 percent or less. Impacts are considered small if there is no change in the school systems' abilities to provide educational services and if no additional teaching staff or classroom space is needed. Moderate impacts generally are associated with 4 to 8 percent increases in enrollment. Impacts are considered moderate if a school system must increase its teaching staff or classroom space even slightly to preserve its pre-project level of service…. Large impacts are associated with project-related enrollment increases greater than 8 percent…." Ref. 4.0-1, Section 3.7.4.1

NRC made impacts to education a Category 2 issue because site- and project-specific factors determine the significance of impacts (Ref. 4.0-1, Section 3.7.4.2). Local factors to be ascertained include: (1) project-related enrollment increases, and (2) status of the student/teacher ratio.

This issue is not applicable to SPS because, as Section 3.2 discusses, Dominion has no plans for refurbishment at SPS.

4.17 Offsite Land Use

4.17.1 Refurbishment

NRC Input

The environmental report must contain "…an assessment of the impact of the proposed action on... land-use... (impacts from refurbishment activities only) within the vicinity of the plant…." 10 CFR 51.53(c)(3)(ii)(I)

"…Impacts may be of moderate significance at plants in low population areas…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 68

"…[I]f plant-related population growth is less than 5 percent of the study area's total population, off-site land-use changes would be small, especially if the study area has established patterns of residential and commercial development, a population density of at least 60 persons per square mile, and at least one urban area with a population of 100,000 or more within 50 miles…." Ref. 4.0-1, Section 3.7.5

NRC made impacts to offsite land use as a result of refurbishment activities a Category 2 issue because land-use changes could be considered beneficial by some community members and adverse by others. Local conditions to be ascertained include: (1) plant-related population growth, (2) patterns of residential and commercial development, and (3) proximity to an urban area with a population of at least 100,000.

This issue is not applicable to SPS because, as Section 3.2 discusses, Dominion has no plans for refurbishment at SPS.

4.17.2 **License Renewal Term**

NRC Input

The environmental report must contain "…[a]n assessment of the impact of the proposed action on …land-use…within the vicinity of the plant…" 10 CFR 51.53(c)(3)(ii)(I)

"Significant changes in land use may be associated with population and tax revenue changes resulting from license renewal." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 69

"…[I]f plant-related population growth is less than five percent of the study area's total population, off-site land-use changes would be small…" Ref. 4.0-1, Section 3.7.5

"If the plant's tax payments are projected to be small, relative to the community's total revenue, new tax-driven land-use changes during the plant's license renewal term would be small, especially where the community has pre-established patterns of development and has provided adequate public services to support and guide development." Ref. 4.0-1, Section 4.7.4.1

NRC made impacts to offsite land use during the license renewal term a Category 2 issue, because land-use changes may be perceived as beneficial by some community members and adverse by others. Therefore, NRC could not assess the potential significance of site-specific offsite land-use impacts (Ref. 4.0-1, Section 4.7.4.1). Site-specific factors to consider in an assessment of new tax-driven land-use impacts include: (1) the size of plant-related population growth compared to the area's total population, (2) the size of the plant's tax payments relative to the community's total revenue, (3) the nature of the community's existing land-use pattern, and (4) the extent to which the community already has public services in place to support and guide development.

The GEIS presents an analysis of offsite land use for the renewal term that is characterized by two components: population-driven and tax-driven impacts (Ref. 4.0-1, Section 4.7.4.1). Based on the GEIS case-study analysis, NRC concludes that all new population-driven land-use changes during the license renewal term at all nuclear plants would be small. Population growth caused by license renewal would represent a much smaller "percentage of the local areas" total population than the percentage presented by operations-related growth (Ref. 4.0-1, Section 4.7.4.2).

<u>**Tax-Revenue-Related Impacts**</u>

NRC has determined that the significance of tax payments as a source of local government revenue would be large if the payments are greater than 20 percent of revenue (Ref. 4.0-1, Section 4.7.2.1).

NRC defined the magnitude of land-use changes as follows (Ref. 4.0-1, Section 4.7.4):

- Small - very little new development and minimal changes to an area's land-use pattern
- Moderate - considerable new development and some changes to land-use pattern
- Large - large-scale new development and major changes in land-use pattern.

NRC further determined that, if a plant's tax payments are projected to be a dominant source of a community's total revenue (i.e., greater than 20 percent of revenue), new tax-driven land-use changes would be large.

Table 2-4 provides a comparison of total tax payments made by Dominion to Surry County and the County's operating budget. For the 4-year period from 1995 through 1998, Dominion's tax payments to Surry County represented approximately 76 percent of the County's total annual property tax revenue and approximately 50 percent of Surry County's annual operating budget. Using NRC's criteria, Dominion's tax payments are of large significance to Surry County. For the reasons presented below, however, Dominion does not anticipate large land-use changes as a result of these tax revenues.

As described in Section 3.2, Dominion does not anticipate refurbishment or construction during the license renewal period. Therefore, Dominion does not anticipate any increase in the assessed value of SPS due to refurbishment-related improvements nor any related tax-increase-driven changes to offsite land use and development patterns.

SPS has been, and would probably continue to be, the dominant source of tax revenue for Surry County. However, despite having this income source since plant construction in 1972, Surry County has not experienced large land-use changes. The SPS environs have remained largely rural, county population growth rates after SPS construction have been minimal, and county planners are not projecting large changes (Ref. 4.17-1). Dominion believes continued operation of SPS would be important to maintaining the current level of development and public services, and does not anticipate plant-induced changes to local land-use and development patterns as a result of license renewal.

Conclusion

Dominion views the continued operation of SPS as a significant benefit to Surry County through direct and indirect salaries and tax contributions to the county's economy. Because population growth related to the license renewal of SPS is expected to be relatively small and there would be no new tax impacts to Surry County land use, Dominion concludes that renewal of SPS's licenses would have a continued beneficial impact on Surry County.

4.18 Transportation

NRC Input

"All applicants shall assess the impact of highway traffic generated by the proposed project on the level of service of local highways during periods of license renewal refurbishment activities and during the term of the renewed license." 10 CFR 51.53(c)(3)(ii)(J)

"Transportation impacts (level of service) of highway traffic generated during plant refurbishment and during the term of the renewed license are generally expected to be of small significance. However, the increase in traffic associated with the additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 70

"Small impacts would be associated with a free flowing traffic stream where users are unaffected by the presence of other users (level of service A) or stable flow in which the freedom to select speed is unaffected, but the freedom to maneuver is slightly diminished (level of service B)." Ref. 4.0-1, Section 3.7.4

NRC made impacts to transportation a Category 2 issue, because impact significance is determined primarily by road conditions existing at the time of the project, which NRC could not forecast for all facilities (Ref. 4.0-1, Section 3.7.4.2). Local road conditions to be ascertained are: (1) level of service conditions, and (2) incremental increase in traffic associated with refurbishment activities and license renewal staff.

As described in Section 3.2, no refurbishment is planned and no refurbishment impacts to local transportation are therefore anticipated. As noted in Section 2.10.2, access to SPS is via state route 650, which carries a level of service (LOS) designation of "A". GEIS Section 3.7.4.2 (Ref. 4.0-1) concluded that impacts to roads with an LOS designation of "A" are small, because the operation of individual users is not substantially affected by the presence of other users. At this level, no delays occur and no improvements are needed. Although GEIS (Ref. 4.0-1, Section 3.7.4.2) states that an LOS designation of "C" is associated with moderate impacts and upgrades of the roadway or control system may be required, the Virginia Department of Transportation considers that the addition of 60 additional cars daily on State Highways 650 and 10 (which has an LOS of "C" in the vicinity of SPS) would not affect the roads' LOS or their operational condition (Ref. 4.18-1) and no improvements are needed.

Dominion's SPS workforce includes 879 permanent and 70 to 100 contract and matrixed employees. One to two times a year, as many as 700 additional workers join the permanent workforce during periodic refueling. Dominion's conservative projection of 60 additional employees associated with license renewal for SPS represents a less than 7 percent increase in the current number of employees and an even smaller percentage of employees present onsite during periodic refueling. Given these employment projections and the LOS designation of "A" for the access road to SPS, and "C" for a highway near SPS, it is consistent with the GEIS to conclude that impacts to transportation would be small and mitigative measures would be unwarranted.

4.19 Historic and Archaeological Resources

NRC Input

The environmental report must contain an assessment of "...whether any historic or archaeological properties will be affected by the proposed project." 10 CFR 51.53(c)(3)(ii)(K)

"Generally, plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the Federal agency to consult with the State Historic Preservation Officer to determine whether there are properties present that require protection." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 71

"Sites are considered to have small impacts to historic and archaeological resources if (1) the State Historic Preservation Officer (SHPO) identifies no significant resources on or near the site; or (2) the SHPO identifies (or has previously identified) significant historic resources but determines they would not be affected by plant refurbishment, transmission lines, and license-renewal term operations and there are no complaints from the affected public about the character; and (3) if the conditions associated with moderate impacts do not occur." Ref. 4.0-1, Section 3.7.7

NRC made impacts to historic and archaeological resources a Category 2 issue because determinations of impacts to historic and archaeological resources are site-specific in nature, and the National Historic Preservation Act mandates that impacts must be determined through consultation with the State Historic Preservation Officer (SHPO) (Ref. 4.0-1, Section 4.7.7.3).

Dominion does not plan any land-disturbing refurbishment activities and no refurbishment-related impacts are therefore anticipated. As described in Section 2.13, no known archaeological or historic sites of significance were threatened during SPS's construction in the 1970s. Transmission line rights-of-way have been categorized. No known archaeological or historic sites of significance have been identified; therefore, continued use of transmission lines and rights-of-way is projected to cause little or no impact. Dominion has corresponded with the SHPO by letter dated April 12, 2000, and is awaiting agency response. See Section 9.1.4 and Appendix D for correspondence.

4.20 Severe Accident Mitigation Alternatives (SAMAs)

NRC Input

The environmental report must contain a consideration of alternatives to mitigate severe accidents "... if the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environment assessment..." 10 CFR 51.53(c)(3)(ii)(L)

"... The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives..." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 76

The term "accident" in the current context refers to any unintentional event (i.e., outside the normal or expected plant operational parameters) that results in the release or the potential for release of radioactive material to the environment. Generally, NRC categorizes accidents as "design-basis" or "severe." Design-basis accidents are those for which the risk is great enough that an applicant is required to design and construct a plant to prevent unacceptable accident consequences. Severe accidents are those considered too unlikely to warrant design controls.

Historically, NRC has not included in its environmental impact statements or environmental assessments any analysis of alternative ways to mitigate the environmental impact of severe accidents. A 1989 court decision ruled that, in the absence of an NRC finding that severe accidents are remote and speculative, severe accident mitigation alternatives (SAMAs) should be considered in the NEPA analysis (*Limerick Ecology Action v. NRC*, 869 F.d 719 [3rd Cir. 1989]). For most plants, including SPS, license renewal is the first licensing action that would necessitate consideration of SAMAs.

The NRC concluded in its generic license renewal rulemaking that the unmitigated environmental impacts from severe accidents meet the Category 1 criteria. However, NRC made consideration of mitigation alternatives a Category 2 issue because ongoing regulatory programs related to mitigation (i.e., Individual Plant Examination [IPE] and Accident Management) were not complete for all plants. Because these programs have identified plant programmatic and procedural improvements (and, in a few cases, minor modifications) as cost-effective in reducing severe accident risk and consequences, NRC thought it premature to draw a generic conclusion as to whether severe accident mitigation would be required for license renewal. Site-specific information to be presented in the environmental report includes: (1) potential SAMAs; (2) benefits and costs of implementing potential SAMAs; and (3) sensitivity of analysis to changes in key underlying assumptions.

The overall approach taken in this SAMA analysis includes the following steps:

- Establish the base case - Use NUREG/BR-0184 (Ref. 4.20-1, Chapter 5) to evaluate severe accident impacts. Include offsite exposure cost; offsite economic cost; onsite exposure cost; onsite economic cost, including both cleanup and decommissioning; and replacement power.
- Identify potential SAMAs from sources such as NRC, industry documentation that discusses potential plant improvements, plant-specific sources such as the SPS IPE, and Individual Plant Examination – External Events (IPEEE), as well as insight provided by SPS's probabilistic risk assessment (PRA) staff.
- Qualitatively screen potential SAMAs. Eliminate obviously non-viable candidates, based on objective screening criteria.
- Perform benefit/cost evaluations for remaining SAMAs. Calculate the net value of implementing each remaining SAMA by subtracting the cost of implementing each SAMA from the benefit of each SAMA (averted offsite exposure and economic costs, as well as onsite exposure and economic costs).
- Identify any SAMAs having positive net values.

The SPS SAMA analysis is presented in the following sections and in Appendix G, providing a detailed discussion of the process presented above.

4.20.1 Establishing the Base Case

The purpose of establishing the base case is to provide the baseline for determining risk reductions that would be attributable to the implementation of potential SAMAs. This severe accident risk, based on the SPS PRA model, is evaluated in terms of dollars by using PRA analysis techniques. This analysis includes three levels. The first two levels are defined as follows: level 1 determines core damage frequencies based on system analyses and human-factor evaluations; and level 2 determines the physical and chemical phenomena that affect the performance of the containment and other radiological release mitigation features to quantify accident behavior and release of fission products to the environment. The primary source of data relating to the levels 1 and 2 analyses is the SPS PRA model.

Using the results of these analyses, the next step is to perform a level 3 PRA analysis, which calculates the hypothetical impacts of severe accidents on the surrounding environment and members of the public. The level 3 analysis was performed using the Melcor Accident Consequence Code System (MACCS2). MACCS2 simulates the impact of severe accidents at nuclear power plants on the surrounding environment. The MACCS2 computer code is used for determining the offsite impacts for the level 3 analysis, whereas the magnitude of the onsite impacts (in terms of clean-up and decontamination costs and occupational dose) are based on information provided in NUREG/BR-0184 (Ref. 4.20-1).

The principal phenomena analyzed are: atmospheric transport of radionuclides; mitigative actions (i.e., evacuation, condemnation of contaminated crops and milk) based on dose projection; dose accumulation by a number of pathways, including food and water ingestion; and economic costs. Input for the level 3 analysis includes the SPS core radionuclide inventory, source terms from the PRA model, site meteorological data, projected population distribution (within a 50-mile radius) for the year 2030, emergency response evacuation modeling, and economic data.

4.20.1.1 Offsite Exposure Costs

The level 3 base case analysis shows an annual avoided offsite exposure risk of 18.2118 person-rem (Ref. 4.20-2). This calculated value is converted to a monetary equivalent (dollars) via application of the NRC's conversion factor of \$2,000 per person-rem (Ref. 4.20-3 and Appendix G). This dollar amount is then discounted to present value using NRC methodology (Ref. 4.20-1):

$$APE = (F_S D_{P_S} - F_A D_{P_A}) R \frac{1 - e^{-rt_f}}{r} \qquad (1)$$

where:

APE = monetary value of avoided accident risk due to population doses (after discounting)

R = monetary equivalent of unit dose (\$2,000/person-rem)

F = accident frequency (events/yr)

D_P = population dose factor (person-rem/event)

S = subscript denoting status quo (current conditions)

A = subscript denoting status after implementation of proposed action

r = real discount rate = 7 percent (as a fraction, 0.07)

t_f = years remaining until end of facility life (20 years)

Using a 20-year period for remaining plant life and a 7 percent discount rate results in the monetary equivalent value of offsite exposure costs of \$392,024 (Table 4-5).

4.20.1.2 Offsite Economic Costs

The level 3 analysis shows an annual offsite economic risk of $39,585 (Ref. 4.20-2 and Table 4-5). Calculated values of offsite economic costs caused by severe accidents are also discounted to present value. Discounting is performed in the same manner as for the public health risks in accordance with NRC methodology.

$$AOC = (F_S P_{D_S} - F_A P_{D_A}) \frac{1 - e^{-rt_f}}{r} \qquad (2)$$

where:

AOC = monetary value of avoided accident risk due to offsite property damage (after discounting)

P_D = offsite property loss factor (dollars/event)

The resulting monetary equivalent of offsite economic costs is $426,048, as presented in Table 4-5.

4.20.1.3 Onsite Exposure Costs

Values for occupational exposure from severe accidents are not derived from the PRA model, but are instead obtained from information published by the NRC (Ref. 4.20-1, Section 5.7.3). The values for occupational exposure consist of "immediate dose" and "long-term dose." The best-estimate value provided by the NRC for immediate occupational dose is 3,300 person-rem and for long-term occupational dose is 20,000 person-rem (over a 10-year clean-up period). The following equations are applied to these values to calculate monetary equivalents:

Immediate Dose

For a currently operating facility, NUREG/BR-0184 (Ref. 4.20-1, Section 5.7.3) recommends using the following methodology to calculate the immediate dose present value:

$$W_{io} = (F_s D_{io_S} - F_A D_{io_A}) R \frac{1 - e^{-rt_f}}{r} \qquad (3)$$

where:

W_{io} = monetary value of avoided accident risk due to immediate doses (after discounting)

iO = subscript denoting immediate occupational dose

R = monetary equivalent of unit dose, ($/person-rem)

F = accident frequency (events/yr)

D_{iO} = immediate occupational dose (person-rem/event)

S = subscript denoting status quo (current conditions)

A = subscript denoting status after implementation of proposed action

r = real discount rate

t_f = years remaining until end of facility life

The values used in the analysis are:

R = $2000/person rem

r = 0.07

D_{iO} = 3,300 person-rem/accident (best estimate)

t_f = 20 years

Assuming F_A (accident frequency) is zero for the base case, the monetary value of the immediate dose associated with the plant accident risk is:

$$W_{io} = (F_s D_{io_s}) R \frac{1 - e^{-rt_f}}{r}$$

$$= 3300 * F * \$2,000 * \frac{1 - e^{-0.07*20}}{0.07}$$

The core damage frequency for the base case is 3.78×10^{-5}/year; therefore,

W_{io} = $2,687. The monetary equivalent of short-term exposure costs is $2,687.

<u>Long-Term Dose</u>

For a currently operating facility, NUREG/BR-0184 (Ref. 4.20-1, Section 5.7.3) recommends calculating the long-term dose present value using the following methodology:

$$W_{LTO} = (F_S D_{LTO_s} - F_A D_{LTO_A}) R * \frac{1 - e^{-rt_f}}{r} * \frac{1 - e^{-rm}}{rm} \qquad (4)$$

where:

W_{LTO} = monetary value of accident-risk-avoided long term doses (after discounting)

LTO = subscript denoting long-term occupational doses

m = years over which long-term doses accrue

The values used in the analysis are:

R = $2000/person rem

r = 0.07

D_{LTO} = 20,000 person-rem/accident (best estimate)

m = "as long as 10 years"

t_f = 20 years

For the basis discount rate, assuming F_A is zero, the monetary value of the long-term dose associated with the plant accident risk is:

$$W_{LTO} = (F_S D_{LTO_S}) R * \frac{1 - e^{-rt_f}}{r} * \frac{1 - e^{-rm}}{rm}$$

$$= (F_S \times 20,000) * \$2,000 * \frac{1 - e^{-0.07*20}}{0.07} * \frac{1 - e^{-0.07*10}}{0.07*10}$$

The core damage frequency for the base case is 3.78×10^{-5}/year; therefore,

$W_{LTO} = \$11,712.$ The monetary equivalent of long-term exposure costs is $11,712.

Total Occupational Exposures

As shown in Table 4-5, combining the immediate and long-term dose equations and using the numeric values given above, the long-term accident-related-onsite (occupational) exposure avoided (AOE) is:

$AOE = W_{io} + W_{LTO}$ ($)

The best estimate value for occupational exposure (AOE_B) is:

$AOE_B = W_{io} + W_{LTO} = \$2,687 + \$11,712 = \$14,399$

4.20.1.4 Onsite Economic Costs

Clean-up/Decontamination

The total cost of clean-up and decontamination of a power reactor facility following a severe accident is estimated in NUREG/BR-0184 to be $\$1.5 \times 10^9$; this value is also adopted for these analyses. Considering a 10-year clean-up period, the present value of this cost is:

$$PV_{CD} = \left(\frac{C_{CD}}{m}\right)\left(\frac{1 - e^{-rm}}{r}\right)$$

where:

PV_{CD} = present value of the cost of clean-up/decontamination

C_{CD} = total cost of the clean-up/decontamination effort

m = clean-up period

r = discount rate

Therefore, based upon the values previously assumed:

$$PV_{CD} = \left(\frac{\$1.5E+9}{10}\right)\left(\frac{1 - e^{-0.07*10}}{0.07}\right)$$

$PV_{CD} = \$1.079E+9$

This cost is integrated over the license term of the proposed extension as follows:

$$U_{CD} = PV_{CD}\frac{1 - e^{-rt_f}}{r}$$

where:

U_{CD} = net present value of clean-up/decontamination over the life of the plant

Based upon the values previously assumed:

$U_{CD} = \$1.079E+9\ [10.763])$

$U_{CD} = \$1.161E+10$

Replacement Power Costs

Replacement power costs, $U_{RP,}$ are an additional contributor to onsite costs. These are calculated in accordance with NUREG/BR-0184 (Ref. 4.20-1, Section 5.6.7.2.) Because replacement power will be needed for that time period following a severe accident for the remainder of the expected generating plant life, long-term power replacement calculations have been used. For a generic plant of 910 MWe, the present value of replacement power is calculated as follows:

$$PV_{RP} = \left(\frac{\$1.2E+8}{r}\right)(1-e^{-rt_f})^2$$

where:

PV_{RP} = present value of the cost of replacement power for a single event

t_f = years remaining until end of facility life

r = discount rate

The $1.2 × 10^8 value has no intrinsic meaning, but is a substitute for a string of non-constant replacement power costs that occur over the lifetime of a "generic" reactor after an event (Ref. 4.20-1, Section 5.7.6). This equation was developed per NUREG/BR-0184 for discount rates between 5 and 10 percent only.

For discount rates between 1 and 5 percent, Ref. 4.20-1 indicates that a linear interpolation is appropriate between present values of $1.2 × 10^9 at 5 percent and $1.6 × 10^9 at 1 percent. For discount rates in this range, the following equation was used to perform the linear interpolation.

$$PV_{RP} = (\$1.6E+9) - \left(\frac{[(\$1.6E+9)-(\$1.2E+9)]}{[5\% - 1\%]} * [r_s - 1\%]\right)$$

where:

r_s = discount rate (small), between 1 percent and 5 percent

To account for the entire lifetime of the facility, U_{RP} was then calculated from PV_{RP} as follows:

$$U_{RP} = \frac{PV_{RP}}{r}(1-e^{-rt_f})^2$$

where:

U_{RP} = present value of the cost of replacement power over the life of the facility

Again, this equation is only applicable in the range of discount rates from 5 to 10 percent. NUREG/BR-0184 states that, for lower discount rates, linear interpolations for U_{RP} are recommended between $1.9 $\times 10^{10}$ at 1 percent and $1.2 $\times 10^{10}$ at 5 percent. Therefore, for the sensitivity analysis, which considers a 3 percent discount rate, the following equation was used to perform this linear interpolation:

$$U_{RP} = (\$1.9E + 10) - \left(\frac{[(\$1.9E + 10) - (\$1.2E + 10)]}{[5\% - 1\%]} * [r_s - 1\%]\right)$$

where:

r_s = discount rate (small), between 1 and 5 percent

SPS has a gross electrical output of 855.4 MWe and a net of 801 MWe, compared to the generic plant of 910 MWe. Therefore, the replacement power formula could be reduced by a factor of 0.94, but the generic formula will be conservatively used.

Repair and Refurbishment

Dominion has no plans for major repair/refurbishment following a severe accident; therefore, there is no contribution to averted onsite costs from this source.

Total Onsite Economic Costs

The total averted onsite economic cost is, therefore:

$AOSC = F * (U_{CD} + U_{RP})$

where:

F = annual frequency of the event

AOSC = averted onsite economic cost

AOSC = $737,672. The monetary equivalent of total averted economic onsite costs is $737,672.

4.20.2 SAMA Identification and Screening

The list of potential enhancements was developed by reviewing industry documents from which reasonable ideas could be gleaned. In addition to the industry sources, plant-specific sources were also reviewed. The SPS IPE and IPEEE were examined to determine if there were any additional plant-specific improvements that had not been evaluated in those documents. The SPS PRA staff also provided several plant-specific items that were included in the evaluation. Finally, the top 100 cutsets of the updated level 1 PRA were examined to identify the important contributors to plant risk (both plant equipment and operator actions). Shutdown-related improvements are not addressed explicitly. However, SAMAs that affect structures, systems, and components that may enhance mitigative functions during both at-power and shutdown conditions are addressed.

The comprehensive set of sources considered in developing the SAMA list is as follows:

- The SPS IPE submittal (only items not already evaluated and/or implemented during the IPE) (Ref. G.2.1 in Appendix G)
- The Watts Bar Nuclear Plant Unit 1 PRA/IPE submittal (Ref. G.2.2 in Appendix G)
- The Limerick severe accident mitigation design alternatives (SAMDA) cost estimate report (Ref. G.2.3 in Appendix G)
- NUREG-1437 description of Limerick SAMDA (Ref. G.2.4 in Appendix G)
- NUREG-1437 description of Comanche Peak SAMDA (Ref. G.2.5 in Appendix G)
- Watts Bar SAMDA submittal (Ref. G.2.6 in Appendix G)
- TVA response to NRC's Request for Additional Information on the Watts Bar SAMDA submittal (Ref. G.2.7 in Appendix G)
- Westinghouse AP600 SAMDA (Ref. G.2.8 in Appendix G)
- Safety Assessment Consulting presentation by Wolfgang Werner at the NUREG-1560 conference (Ref. G.2.9 in Appendix G)
- NRC IPE Workshop - NUREG-1560 NRC Presentation (Ref. G.2.10 in Appendix G)
- NUREG-0498, Supplement 1, Section 7 (Ref. G.2.11 in Appendix G)
- NUREG/CR-5567, Pressurized Water Reactor (PWR) Dry Containment Issue Characterization (Ref. G.2.12 in Appendix G)
- NUREG-1560, Volume 2, NRC Perspectives on the IPE Program (Ref. G.2.13 in Appendix G)
- NUREG/CR-5630, PWR Dry Containment Parametric Studies (Ref. G.2.14 in Appendix G)
- NUREG/CR-5575, Quantitative Analysis of Potential Performance Improvements for the Dry PWR Containment (Ref. G.2.15 in Appendix G)
- CE System 80+ Submittal (Ref. G.2.16 in Appendix G)

- NUREG-1462, NRC Review of ABB/CE System 80+ Submittal (Ref. G.2.17 in Appendix G)
- An ICONE paper by C. W. Forsberg, et al., on a core melt source reduction system (Ref. G.2.18 in Appendix G)
- The SPS IPEEE submittal (only those items not already evaluated and/or implemented during the IPEEE) (Ref. G.2.19 in Appendix G)
- Additional items from the SPS PRA staff or from review of the top 100 cutsets

Although SPS is a Westinghouse design, all above documents were reviewed for potential SAMAs, even if they were not necessarily applicable to a Westinghouse plant. Those items not applicable to SPS were subsequently removed from the list. The containment performance improvement programs for boiling water reactors and ice condenser plants were not reviewed (and the NUREG-1560 portion of the containment performance improvement for these was not reviewed). Conceptual enhancement for which no specific details were available (e.g., "improve diesel reliability" or "improve procedures for loss of support systems") were not included, unless they were considered as vulnerabilities in the SPS IPE.

The SAMAs that have been identified for consideration are presented in Table 1 in Appendix G. The list included a total of 160 items.

4.20.2.1 Qualitative Screening of SAMAs

The last two columns of Table 1 in Appendix G present the qualitative screening of the initial list. Items were eliminated from further evaluation based on one of the following criteria:

- The SAMA was not applicable at SPS, either because the enhancement was only for boiling water reactors, the Westinghouse AP600 design, or PWR ice condenser containments, or it was a plant-specific enhancement that did not apply at SPS (Criterion A); or
- The SAMA had already been implemented at SPS (or the SPS design met the intent of the SAMA) (Criterion B), or
- The SAMA was related to a reactor coolant pump (RCP) seal vulnerability at many PWRs, stemming from charging pump dependency on Component Cooling Water (CCW). The SPS does not have this vulnerability because the charging pumps do not rely on CCW. However, other RCP seal loss-of-coolant accident (LOCA) improvements were still considered (Criterion C).

Based on preliminary screening, 107 SAMAs were either eliminated or combined with other potential improvements, leaving 53 SAMAs subject to the benefit/cost process. These improvements are listed in Table 4-6. The benefit/cost portion of Table 4-6 is described in Section 4.20.2.2.

4.20.2.2 Benefit/Cost Analyses

The final screening process involved identifying and eliminating those items whose cost exceeded their benefit.

The SAMA benefit is evaluated in dollar terms by using PRA analysis techniques. This includes levels 1 and 2 results, using the SPS PRA model, and a level 3 analysis, using the MACCS2 code (Ref. 4.20-4).

The level 3 results are determined based on the grouped level 2 containment release frequencies, and encompass both onsite and offsite consequences. The onsite consequences are proportional to core damage, while the offsite consequences differ for each containment release category. The consequences include a radiation dose term (in person-rem) and a property loss (cost) term in dollars. As described in Section 4.20.1, the dose term is converted to dollars and added to the property losses for both onsite and offsite consequences. The reduction in the total potential cost of an accident by implementing a SAMA constitutes the benefit of that SAMA. This benefit is compared with the estimated cost of implementing the SAMA to determine the overall net value of implementing that SAMA.

The maximum theoretical benefit (also called Maximum Attainable Benefit, or MAB) is based upon the elimination of all plant risk and equates to the previously calcuated base case risk. The costs associated with those SAMAs that involve major plant modifications may simply be compared with this benefit as a means of eliminating them from further consideration (e.g., a SAMA that would require construction of a large structure might be compared with the maximum attainable benefit).

Staff experienced in estimating the cost of performing work at a nuclear power plant prepared all the SAMA cost analyses. The depth of analysis performed varied, depending on the magnitude of the expected benefit. Detailed cost estimating was performed only in those situations in which the expected benefit is significant. For all other SAMAs, order of magnitude estimates of the hardware modifications were sufficient. To account for uncertainty in the cost estimates, Table 4-6 shows that all of the SAMAs screened with a cost that was at least twice the calcualted benefit. Therefore, even if the cost estimates were to vary from the order of magnitude estimate, they would have to differ by at least a factor of two before becoming significant. The factor of two presented in Table 4-6 was chosesn arbitrarily, but provided confidence that even when uncertaninties are considered, the conclusions would not change. If a SAMA involved a hardware modification, it was assumed that the cost would be at least $100,000. For the generation of a new procedure and its implementation, it was assumed that the cost would be at least $30,000.

Benefit Calculations

For each SAMA evaluation, a revised set of plant damage state frequencies was generated. Using the revised plant damage state frequencies, a revised level 3 dollars-averted calculation was performed. The results are presented in Table 6 of Ref. 4.20-2.

Each evaluation in Appendix G contains a description of the plant change that is represented by the case, a description of the changes that were made in the fault trees, event trees, and/or databases in the PRA to calculate the benefit. In addition, each case contains the summary results of the fault tree analysis for the case, in the form of improvement in core damage frequency and in offsite release frequency. The results of these benefit calculations are presented in Table 4-6.

The PRA calculations of SAMA benefit are recognized to have some uncertainty around the mean frequencies used in the analyses. Some of the uncertainty is related to quantifiable uncertainty distributions of the data, while other stems from unquantifiable uncertainty in the PRA assumptions. To account for the possible uncertainty, rather than perform a quantitative uncertainty analysis, several sensitivity analyses on key input information were performed to bound the analysis.

Cost Estimates

The cost estimates were generally made as an order of magnitude approximation. For most of the SAMAs considered, the conservative cost estimates were sufficiently greater than the benefits calculated, such that no additional evaluation was required. The cost estimates were generated by SPS staff and are presented in Table 4-6.

The benefits resulting from the bounding estimates presented in the benefit analysis are, in general, rather small. In most cases, the benefits are so small that it is obvious that the implementation costs would exceed the benefits, even without a detailed cost estimate. In many cases, plant staff judgment is applied in assessing whether the benefit approaches the expected implementation costs. Detailed cost estimating is only applied in those situations in which the benefit is significant and application of judgment would be questioned.

4.20.3 **Conclusions**

As shown in Table 4-6, none of the SAMAs analyzed would be justified on a cost-benefit basis. In other words, none of the analyzed modifications would provide more benefits than they would cost.

Dominion performed a sensitivity analysis by substituting a 3 percent discount rate for the 7 percent discount rate used for the above analysis, as recommended in Ref. 4.20-1. This reduced discount rate takes into account the additional uncertainties (i.e., interest rate fluctuations) in predicting costs for activities that would take place several years in the future. The results of this sensitivity analysis are presented in Appendix G, and the results hold true for the range of discounts used in the sensitivity analysis.

TABLES

Table 4-1
Category 1 Issues That Do Not Apply to Surry Power Station (SPS)[a]

Issues	Basis for Inapplicablity to SPS
Surface Water Quality, Hydrology, and Use (for all plants)	
1. Impacts of refurbishment on surface water quality	Impacts apply to an activity, refurbishment, that SPS will not undertake.
2. Impacts of refurbishment on surface water use	Impacts apply to an activity, refurbishment, that SPS will not undertake.
5. Altered thermal stratification of lakes	Issue applies to a receiving water body, a lake, that SPS does not have.
Aquatic Ecology (for all plants)	
14. Refurbishment impacts to aquatic resources	Impacts apply to an activity, refurbishment, that SPS will not undertake.
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)	
28. Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	Issue applies to a heat dissipation system, cooling towers, that SPS does not have.
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	Issue applies to a heat dissipation system, cooling towers, that SPS does not have.
30. Heat shock for plants with cooling-tower-based heat dissipation systems	Issue applies to a heat dissipation system, cooling towers, that SPS does not have.
Groundwater Use and Quality	
31. Impacts of refurbishment on groundwater use and quality	Impacts apply to an activity, refurbishment, that SPS will not undertake.
32. Groundwater use conflicts (potable and service water; plants that use <100 gallons per minute [gpm])	Issue applies to plants that withdraw less than 100 gpm groundwater; Surry uses more than 100 gpm groundwater.
36. Groundwater quality degradation (Ranney wells)	Issue applies to a heat dissipation system feature, Ranney wells, that SPS does not have.
38. Groundwater quality degradation (cooling ponds in salt marshes)	Issue applies to a heat dissipation system, cooling ponds, that SPS does not have.

Table 4-1 (continued)
Category 1 Issues That Do Not Apply to
Surry Power Station (SPS)[a]

Issues	Basis for Inapplicablity to SPS
Terrestrial Resources	
41. Cooling tower impacts on crops and ornamental vegetation	Issue applies to a heat dissipation system feature, cooling towers, that SPS does not have.
42. Cooling tower impacts on native plants	Issue applies to a heat dissipation system feature, cooling towers, that SPS does not have.
43. Bird collisions with cooling towers	Issue applies to a heat dissipation system feature, cooling towers, that SPS does not have.
44. Cooling pond impacts on terrestrial resources	Issue applies to a heat dissipation system feature, cooling ponds, that SPS does not have.
Human Health	
54. Radiation exposures to the public during refurbishment	Impacts apply to an activity, refurbishment, that SPS will not undertake.
55. Occupational radiation exposures during refurbishment	Impacts apply to an activity, refurbishment, that SPS will not undertake.
Socioeconomics	
72. Aesthetic impacts (refurbishment)	Impacts apply to an activity, refurbishment, that SPS will not undertake.

a. NRC listed the issues in Table B-1 of 10 CFR 51 Appendix B. Dominion added issue numbers for expediency.

Table 4-2
Category 1 and NA Issues That Apply to Surry Power Station (SPS)[a]

Issue	NRC Findings[b]	GEIS Reference (Section/Page)
Surface Water Quality, Hydrology, and Use (for all plants)		
3. Altered current patterns at intake and discharge structures	SMALL. Altered current patterns have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.	4.2.1.2.1/4-4
4. Altered salinity gradients	SMALL. Salinity gradients have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.	4.2.1.2.2/4-4
6. Temperature effects on sediment transport capacity	SMALL. These effects have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.	4.2.1.2.3/4-6
7. Scouring caused by discharged cooling water	SMALL. Scouring has not been found to be a problem at most operating nuclear power plants and has caused only localized effects at a few plants. It is not expected to be a problem during the license renewal term.	4.4.2.2/4-6
8. Eutrophication	SMALL. Eutrophication has not been found to be a problem at operating nuclear power plants and is not expected to be a problem during the license renewal term.	4.2.1.2.3/4-6
9. Discharge of chlorine or other biocides	SMALL. Effects are not a concern among regulatory and resource agencies and are not expected to be a problem during the license renewal term.	4.2.1.2.4/4-10
10. Discharge of sanitary wastes and minor chemical spills	SMALL. Effects are readily controlled through National Pollutant Discharge Elimination System (NPDES) permit and periodic modifications, if needed, and are not expected to be a problem during the license renewal term.	4.2.1.2.4/4-10
11. Discharge of other metals in waste water	SMALL. These discharges have not been found to be a problem at operating nuclear power plants with cooling-tower-based heat dissipation systems and have been satisfactorily mitigated at other plants. They are not expected to be a problem during the license renewal term.	4.2.1.2.4/4-10
12. Water use conflicts (plants with once-through cooling systems)	SMALL. These conflicts have not been found to be a problem at operating nuclear power plants with once-through heat dissipation systems.	4.2.1.3/4-13
Aquatic Ecology (for all plants)		
15. Accumulation of contaminants in sediments or biota	SMALL. Accumulation of contaminants has been a concern at a few nuclear power plants, but has been satisfactorily mitigated by replacing copper alloy condenser tubes with those of another metal. It is not expected to be a problem during the license renewal term.	4.2.1.2.4/4-10

Table 4-2 (continued)
Category 1 and NA Issues That Apply to Surry Power Station (SPS)[a]

Issue	NRC Findings[b]	GEIS Reference (Section/Page)
16. Entrainment of phytoplankton and zooplankton	SMALL. Entrainment of phytoplankton and zooplankton has not been found to be a problem at operating nuclear power plants and is not expected to be a problem during the license renewal term.	4.2.2.1.1/4-15
17. Cold shock	SMALL. Cold shock has been satisfactorily mitigated at operating nuclear plants with once-through cooling systems, has not endangered fish populations or been found to be a problem at operating nuclear power plants with cooling towers or cooling ponds, and is not expected to be a problem during the license renewal term.	4.2.2.1.5/4-18
18. Thermal plume barrier to migrating fish	SMALL. Thermal plumes have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.	4.2.2.1.6/4-19
19. Distribution of aquatic organisms	SMALL. Thermal discharge may have localized effects, but is not expected to affect the larger geographical distribution of aquatic organisms.	4.2.2.1.6/4-19
20. Premature emergence of aquatic insects	SMALL. Premature emergence has been found to be a localized effect at some operating nuclear power plants, but has not been a problem and is not expected to be a problem during the license renewal term.	4.2.2.1.7/4-20
21. Gas supersaturation (gas bubble disease)	SMALL. Gas supersaturation was a concern at a small number of operating nuclear power plants with once-through cooling systems, but has been satisfactorily mitigated. It has not been found to be a problem at operating nuclear power plants with cooling towers or cooling ponds and is not expected to be a problem during the license renewal term.	4.2.2.1.8/4-21
22. Low dissolved oxygen in the discharge	SMALL. Low dissolved oxygen has been a concern at one nuclear power plant with a once-through cooling system but has been effectively mitigated. It has not been found to be a problem at operating nuclear power plants with cooling towers or cooling ponds and is not expected to be a problem during the license renewal term.	4.2.2.1.9/4-23
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	SMALL. These types of losses have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal term.	4.2.2.1.10/4-24

Table 4-2 (continued)
Category 1 and NA Issues That Apply to Surry Power Station (SPS)[a]

Issue	NRC Findings[b]	GEIS Reference (Section/Page)
24. Stimulation of nuisance organisms (e.g., shipworms)	SMALL. Stimulation of nuisance organisms has been satisfactorily mitigated at the single nuclear power plant with a once-through cooling system where it was previously a problem. It has not been found to be a problem at operating nuclear power plants with cooling towers or cooling ponds and is not expected to be a problem during the license renewal term.	4.2.2.1.11/4-25
Groundwater Use and Quality		
37. Groundwater quality degradation (saltwater intrusion)	SMALL. Nuclear power plants do not contribute significantly to saltwater intrusion.	4.8.2.1/4-119
Terrestrial Resources		
45. Power line right-of-way management (cutting and herbicide application)	SMALL. The impacts of right-of-way maintenance on wildlife are expected to be of small significance at all sites.	4.5.6.1/4-71
46. Bird collisions with power lines	SMALL. Impacts are expected to be of small significance at all sites.	4.5.6.2/4-74
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	SMALL. No significant impacts of electromagnetic fields on terrestrial flora and fauna have been identified. Such effects are not expected to be a problem during the license renewal term.	4.5.6.3/4-77
48. Floodplains and wetlands on power line right-of-way	SMALL. Periodic vegetation control is necessary in forested wetlands underneath power lines and can be achieved with minimal damage to the wetland. No significant impact is expected at any nuclear power plant during the license renewal term.	4.5.7/4-81
Air Quality		
51. Air quality effects of transmission lines	SMALL. Production of ozone and oxides of nitrogen is insignificant and does not contribute measurably to ambient levels of these gases.	4.5.2/4-62 3.2/3-1
Land Use		
52. Onsite land use	SMALL. Projected onsite land use changes required during refurbishment and the renewal period would be a small fraction of any nuclear power plant site and would involve land that is controlled by the applicant.	3.2/3-1
53. Power line right-of-way land use impacts	SMALL. Ongoing use of power line rights-of-way would continue with no change in restrictions. The effects of these restrictions are of small significance.	4.5.3/4-62

Table 4-2 (continued)
Category 1 and NA Issues That Apply to Surry Power Station (SPS)[a]

Issue	NRC Findings[b]	GEIS Reference (Section/Page)
Human Health		
56. Microbiological organisms (occupational health)	SMALL. Occupational health impacts are expected to be controlled by continued application of accepted industrial hygiene practices to minimize worker exposures.	4.3.6/4-48
58. Noise	SMALL. Noise has not been found to be a problem at operating plants and is not expected to be a problem at any plant during the license renewal term.	4.3.7/4-49
60. Electromagnetic fields, chronic effects	UNCERTAIN. Biological and physical studies of 60-Hz electromagnetic fields have not found consistent evidence linking harmful effects with field exposure. However, research is continuing in this area and a consensus scientific view has not been reached.	4.5.4.2/4-67
61. Radiation exposures to public (license renewal term)	SMALL. Radiation doses to the public will continue at current levels associated with normal operations.	4.6.2/4-87
62. Occupational radiation exposures (license renewal term)	SMALL. Projected maximum occupational doses during the license renewal term are within the range of doses experienced during normal operations and normal maintenance outages, and would be well below regulatory limits.	4.6.3/4-95
Socioeconomics		
64. Public services: public safety, social services, and tourism and recreation	SMALL. Impacts to public safety, social services, and tourism and recreation are expected to be of small significance at all sites.	4.7.3/4-104 (renewal - public services) 4.7.3.3/4-106 (renewal - safety) 4.7.3.4/4-107 (renewal - social services) 4.7.3.6/4-107 (renewal - tourism, recreation)
67. Public services: education (license renewal term)	SMALL. Only impacts of small significance are expected.	4.7.3.1/4-106
73. Aesthetic impacts (license renewal term)	SMALL. No significant impacts are expected during the license renewal term.	4.7.6/4-111
74. Aesthetic impacts of transmission lines (license renewal term)	SMALL. No significant impacts are expected during the license renewal term.	4.5.8/4-83

Table 4-2 (continued)
Category 1 and NA Issues That Apply to Surry Power Station (SPS)[a]

Issue	NRC Findings[b]	GEIS Reference (Section/Page)
Postulated Accidents		
75. Design basis accidents	SMALL. The NRC staff has concluded that the environmental impacts of design basis accidents are of small significance for all plants.	5.3.2/5-11 (design basis) 5.5.1/5-114 (summary)
Uranium Fuel Cycle and Waste Management		
77. Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	SMALL. Offsite impacts of the uranium fuel cycle have been considered by the Commission in Table S-3 of this part. Based on information in the GEIS, impacts on individuals from radioactive gaseous and liquid releases, including radon-222 and technetium-99, are small.	6.2/6-8
78. Offsite radiological impacts (collective effects)	The 100-year environmental dose commitment to the U.S. population from the fuel cycle, high-level waste, and spent fuel disposal is calculated to be about 14,800 person-rem, or 12 cancer fatalities, for each additional 20-year power reactor operating term. Much of this, especially the contribution of radon releases from mines and tailing piles, consists of tiny doses summed over large populations. This same dose calculation can theoretically be extended to include many tiny doses over additional thousands of years, as well as doses outside the U.S. The result of such a calculation would be thousands of cancer fatalities from the fuel cycle, but this result assumes that even tiny doses have some statistical adverse health effect, which will not ever be mitigated (for example, no cancer cure in the next thousand years), and that these dose projections over thousands of years are meaningful. However, these assumptions are questionable. In particular, science cannot rule out the possibility that there will be no cancer fatalities from these tiny doses. For perspective, the doses are very small fractions of regulatory limits, and even smaller fractions of natural background exposure to the same populations. Nevertheless, despite all the uncertainty, some judgment as to the regulatory NEPA implications of these matters should be made and it makes no sense to repeat the same judgment in every case. Even taking the uncertainties into account, the Commission concludes that these impacts are acceptable in that these impacts would not be sufficiently large to require the NEPA conclusion, for any plant, that the option of extended operation under 10 CFR 54 should be eliminated. Accordingly, while the Commission has not assigned a single level of significance for the collective effects of the fuel cycle, this issue is considered Category 1.	Not in GEIS

Table 4-2 (continued)
Category 1 and NA Issues That Apply to Surry Power Station (SPS)[a]

Issue	NRC Findings[b]	GEIS Reference (Section/Page)
79. Offsite radiological impacts (spent fuel and high-level waste disposal)	For the high-level waste and spent-fuel disposal component of the fuel cycle, there are no current regulatory limits for offsite releases of radionuclides for the current candidate repository site. However, if we assume that limits are developed along the lines of the 1995 National Academy of Sciences (NAS) report, "Technical Bases for Yucca Mountain Standards," and that in accordance with the Commission's Waste Confidence Decision, 10 CFR 51.23, a repository can and likely will be developed at some site that will comply with such limits, peak doses to virtually all individuals will be 100 millirem per year or less. However, while the Commission has reasonable confidence that these assumptions will prove correct, there is considerable uncertainty since the limits are yet to be developed, no repository application has been completed or reviewed, and uncertainty is inherent in the models used to evaluate possible pathways to the human environment. The NAS report indicated that 100 millirem per year should be considered as a starting point for limits for individual doses, but notes that some measure of consensus exists among national and international bodies that the limits should be a fraction of the 100 millirem per year. The lifetime individual risk from the 100-millirem annual dose limit is about $3 [\times] 10^{-3}$. Estimating cumulative doses to populations over thousands of years is more problematic. The likelihood and consequences of events that could seriously compromise the integrity of a deep geologic repository were evaluated by the U.S. Department of Energy in the "Final Environmental Impact Statement: Management of Commercially Generated Radioactive Waste," October 1980. The evaluation estimated the 70-year whole-body dose commitment to the maximum individual and to the regional population resulting from several modes of breaching a reference repository in the year of closure, after 1,000 years, after 100,000 years, and after 100,000,000 years. Subsequently, NRC and other federal agencies have expended considerable effort to develop models for the design and for the licensing of a high-level waste repository, especially for the candidate repository at Yucca Mountain. More meaningful estimates of doses to the population may be possible in the future as more is understood about the performance of the proposed Yucca Mountain repository. Such estimates would involve very great uncertainty, especially with respect to cumulative population doses over thousands of years. The standard proposed by the NAS is a limit on maximum individual dose. The relationship of potential new regulatory requirements, based on the NAS report, and cumulative population impacts has not been determined, although the report articulates the view that protection of individuals will adequately protect the population for a repository at Yucca Mountain. However, the U.S. Environmental Protection Agency's (EPA's)	Not in GEIS

Table 4-2 (continued)
Category 1 and NA Issues That Apply to Surry Power Station (SPS)[a]

Issue	NRC Findings[b]	GEIS Reference (Section/Page)
	generic repository standards in 40 CFR 191 generally provide an indication of the order of magnitude of cumulative risk to the population that could result from the licensing of a Yucca Mountain repository, assuming the ultimate standards will be within the range of standards now under consideration. The standards in 40 CFR 191 protect the population by imposing "containment requirements" that limit the cumulative amount of radioactive material released over 10,000 years. The cumulative release limits are based on EPA's population impact goal of 1,000 premature cancer deaths worldwide for a 100,000 metric tonne (MTHM) repository. Nevertheless, despite all the uncertainty, some judgment as to the regulatory NEPA implications of these matters should be made and it makes no sense to repeat the same judgment in every case. Even taking the uncertainties into account, the Commission concludes that these impacts are acceptable in that these impacts would not be sufficiently large to require the NEPA conclusion, for any plant, that the option of extended operation under 10 CFR 54 should be eliminated. Accordingly, while the Commission has not assigned a single level of significance for the impacts of spent fuel and high-level waste disposal, this issue is considered Category 1.	
80. Nonradiological impacts of the uranium fuel cycle	SMALL. The nonradiological impacts of the uranium fuel cycle resulting from the renewal of an operating license for any plant are small.	6.2.2.6/6-20 (land use) 6.2.2.7/6-20 (water use) 6.2.2.8/6-21 (fossil fuel) 6.2.2.9/6-21 (chemical)
81. Low-level waste storage and disposal	SMALL. The comprehensive regulatory controls that are in place, and the low public doses being achieved at reactors, ensure that the radiological impacts to the environment will remain small during the term of a renewed license. The maximum additional onsite land that may be required for low-level waste storage during the term of a renewed license and associated impacts will be small. Nonradiological impacts on air and water will be negligible. The radiological and nonradiological environmental impacts of long-term disposal of low-level waste from any individual plant at licensed sites are small. In addition, the Commission concludes that there is reasonable assurance that sufficient low-level waste disposal capacity will be made available when needed for facilities to be decommissioned consistent with NRC decommissioning requirements.	6.4.2/6-36 ("low-level" definition) 6.4.3/6-37 (low-level volume) 6.4.4/6-48 (renewal effects)

Table 4-2 (continued)
Category 1 and NA Issues That Apply to Surry Power Station (SPS)[a]

Issue	NRC Findings[b]	GEIS Reference (Section/Page)
82. Mixed waste storage and disposal	SMALL. The comprehensive regulatory controls and the facilities and procedures that are in place ensure proper handling and storage, as well as negligible doses and exposure to toxic materials for the public and the environment at all plants. License renewal will not increase the small, continuing risk to human health and the environment posed by mixed waste at all plants. The radiological and nonradiological environmental impacts of long-term disposal of mixed waste from any individual plant at licensed sites are small. In addition, the Commission concludes that there is reasonable assurance that sufficient mixed waste disposal capacity will be made available when needed for facilities to be decommissioned consistent with NRC decommissioning requirements.	6.4.5/6-63
83. Onsite spent fuel	SMALL. The expected increase in the volume of spent fuel from an additional 20 years of operation can be safely accommodated onsite with small environmental effects through dry or pool storage at all plants, if a permanent repository or monitored retrievable storage is not available.	6.4.6/6-70
84. Nonradiological waste	SMALL. No changes to generating systems are anticipated for license renewal. Facilities and procedures are in place to ensure continued proper handling and disposal at all plants.	6.5/6-86
85. Transportation	SMALL. The impacts of transporting spent fuel enriched up to 5 percent uranium-235 with average burnup for the peak rod to current levels approved by NRC up to 62,000 MWd/MTU and the cumulative impacts of transporting high-level waste to a single repository, such as Yucca Mountain, Nevada, are found to be consistent with the impact values contained in 10 CFR 51.52(c), Summary Table S-4–Environmental Impact of Transportation of Fuel and Waste to and from One Light-Water-Cooled Nuclear Reactor. If fuel enrichment or burnup conditions are not met, the applicant must submit an assessment of the implications for the environmental impact values reported in § 51.52.	Footnote c
	Decommissioning	
86. Radiation doses (decommissioning)	SMALL. Doses to the public will be well below applicable regulatory standards regardless of which decommissioning method is used. Occupational doses would increase no more than 1 man-rem caused by buildup of long-lived radionuclides during the license renewal term.	7.3.1/7-15
87. Waste management (decommissioning)	SMALL. Decommissioning at the end of a 20-year license renewal period would generate no more solid wastes than at the end of the current license term. No increase in the quantities of Class C or greater-than-Class-C wastes would be expected.	7.3.2/7-19 (impacts) 7.4/7-25 (conclusions)

Table 4-2 (continued)
Category 1 and NA Issues That Apply to Surry Power Station (SPS)[a]

Issue	NRC Findings[b]	GEIS Reference (Section/Page)
88. Air quality (decommissioning)	SMALL. Air quality impacts of decommissioning are expected to be negligible either at the end of the current operating term or at the end of the license renewal term.	7.3.3/7-21 (air) 7.4/7-25 (conclusion)
89. Water quality (decommissioning)	SMALL. The potential for significant water quality impacts from erosion or spills is no greater whether decommissioning occurs after a 20-year license renewal period or after the original 40-year operation period, and measures are readily available to avoid such impacts.	7.3.4/7-21 (water) 7.4/7-25 (conclusion)
90. Ecological resources (decommissioning)	SMALL. Decommissioning after either the initial operating period or after a 20-year license renewal period is not expected to have any direct ecological impacts.	7.3.5/7-21 (ecological) 7.4/7-25 (conclusion)
91. Socioeconomic impacts (decommissioning)	SMALL. Decommissioning would have some short-term socioeconomic impacts. The impacts would not be increased by delaying decommissioning until the end of a 20-year relicense period, but they might be decreased by population and economic growth.	7.3.7/7-24 (socioeconomic) 7.4/7-25 (conclusion)
Environmental Justice		
92. Environmental justice	NONE. The need for and the content of an analysis of environmental justice will be addressed in plant-specific reviews.	Not in GEIS

a. NRC listed the issues in Table B-1 of 10 CFR 51 Appendix B. Dominion added issue numbers for expediency.

b. NRC has defined SMALL to mean that, for the issue, environmental effects are not detectable or are so minor that they would neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, NRC has concluded that those impacts that do not exceed permissible levels in the NRC's regulations are considered small. (10 CFR 51 Appendix B, Table B-1, footnote 3).

c. NRC published, on September 3, 1999, a GEIS addendum (Ref. 4.0-3) in support of its rulemaking that re-categorized Issue 85 from 2 to 1.

CFR = Code of Federal Regulations
EPA = U.S. Environmental Protection Agency
GEIS = Generic Environmental Impact Statement (Ref. 4.0-1)
Hz = Hertz
NA = Not applicable. NRC determined that its categorization (1 or 2) and its impact findings definitions (SMALL, MODERATE, LARGE) do not apply to two issues (Issues 60 and 92)
NAS = National Academy of Sciences
NEPA = National Environmental Policy Act
NRC = U.S. Nuclear Regulatory Commission

Table 4-3
Computer Input Parameters for Calculating Groundwater Drawdown

Parameter/Assumptions	Value Range	Value Used
Transmissivity	4,000-6,000 ft^2/day	5,000 ft^2/day
Storage Coefficient	0.00001 – 0.001	0.0003
Aquifer Horizontal Hydraulic Conductivity	NA	438 gallons/day/ft^2
Water Table Storativity	NA	0.0020
Productive Well Effective Radius	NA	0.250 ft
Top of Aquifer Depth	NA	370 ft
Base of Aquifer	NA	455 ft
Initial Water Level Depth	NA	100 ft
Infinite Aquifer System	NA	NA

NA = Not Applicable.

Table 4-4
Results of Induced Current Analysis

Transmission Line	Voltage (kV)	Limiting Case Electric Field Strength (kV/meter)	Limiting Case Induced Current (milliamperes)
212, Hopewell	230	7.11	5.07[a]
214, Whealton	230	6.72	4.79
223, Yadkin	230	6.72	4.79
226, Churchland	230	6.72	4.79
240, Hopewell	230	7.11	5.07[a]
290, Chuckatuck	230	6.72	4.79
531, Yadkin	500	7.11	5.07[a]
567, Chickahominy	500	7.11	5.07[a]
578, Septa	500	6.72	4.79

a. Actual calculation result was 5.068. Given the very slight exceedances, Dominion concludes that electric shock is of small significance.

Table 4-5
Base Case Benefit (in dollars)[a,b]

Parameter	Value
Offsite annual dose (person-rem)	18.2118
Offsite annual economic cost	$39,585
Offsite exposure cost savings (present dollar value)	$392,024
Offsite economic cost savings (present dollar value)	$426,048
Total offsite cost savings	**$818,072**
Onsite short-term exposure cost (best estimate)	$2,687
Onsite long-term exposure cost (best estimate)	$11,712
Cleanup/decontamination cost savings	$439,198
Total onsite cost savings (without replacement power)	**$453,597**
Replacement power cost	$298,474
Total onsite cost (with replacement power)	**$752,071**
Total cost (onsite + replacement power + offsite)	**$1,570,143**

a. Refer to text in Section 4.20 for discussion of how these numbers are calculated.

b. The benefit numbers in this table have not yet been doubled to account for the External Events contribution. For example, the total offsite cost savings is $820k, so doubling it yields a maximum benefit of $1.64 M of containment/Level 2 improvements.

Table 4-6
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
9	Provide additional SW pump	Providing another pump would decrease core damage frequency due to a loss of SW	2.0%	0.3%	$34k	>2 x Benefit	Screen Out	Analysis case SWP determined the maximum benefit to be $34k. Not cost beneficial; cost is estimated to exceed twice the benefit.
10	Create an independent RCP seal injection system, with dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of seal cooling or SBO.	4.0%	0.3%	$63k	>2 x benefit	Screen out	Screening case SLO determined the maximum benefit to be $63k. Not cost beneficial; cost is estimated to exceed twice the benefit.
11	Create an independent RCP seal injection system, without dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of seal cooling, but not SBO.	4.0%	0.3%	$63k	>2 x benefit	Screen out	Screening case SLO determined the maximum benefit to be $63k. Not cost beneficial; cost is estimated to exceed twice the benefit.
14	Install improved RCP seals	RCP seal O-rings constructed of improved materials would reduce chances of RCP seal LOCA	4.0%	0.3%	$63k	>2 x benefit	Screen out	Screening case SLO determined the maximum benefit to be $63k. Not cost beneficial; cost is estimated to exceed twice the benefit.
15	Add a third CCW pump	Reduce chance of loss of CCW	0.02%	0.3%	$5k	>2 x benefit	Screen out	Analysis case CCP determined the maximum benefit to be $5k. Not cost beneficial; cost is estimated to exceed twice the benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
21	Loss of CCW or SW procedural enhancements	The suggested improvements in the reference documents include staggering CCW pump operation when SW fails, cross-tying pumps, or shedding CCW loads to extend heatup time.	0.02%	0.3%	$5k	>2 x benefit	Screen out	The cross-tied system already exists at SPS. The other options would not provide any significant benefit because, although they might delay system failure slightly, they would not prevent it. Analysis case CCP further demonstrates the low benefit from even a significant change to the CC system, showing a benefit of only $5k if a new, completely independent, pump were added. Not cost beneficial; cost is estimated to exceed twice the benefit.
23	Alter circ water valve power supply arrangement	The circ water valve inlet/outlet power supplies are 1J-A/1H and 1J-A/2H. The reliability during a LOOP could be improved by having one of the 1J-A supplies changed to 1H	-0.5%	-0.08%	-$4k	>2 x benefit	Screen out	Analysis case CWV showed that there is actually an increase to the CDF and offsite release by rearranging these power supplies. Not cost beneficial; cost is estimated to exceed twice the benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
25	Provide a non-safety related, redundant train of switchgear ventilation	Provide a non-safety related, redundant train of switchgear ventilation	13.9%	5.0%	$278k	>2 x benefit	Screen out	Analysis case HVC determined the maximum benefit to be $278k. The critical cost is associated with finding room for the AHUs within the Control Room envelope. The AHUs would need to be located outside the existing envelope in an airtight pressure - retaining enclosure and ducted through the envelope walls. Use of the existing ductwork would not be feasible nor would installation of new ductwork to support the operation of these new AHUs. They would simply terminate at the envelope walls for both their suction and return air flows. Space for the equipment outside the envelope may not be available, making this modification not feasible. If space could be found, the cost for relocation of existing equipment for space considerations and installation of this system would be $15-25M. Not cost beneficial; cost is estimated to exceed twice the benefit.
27	Add a switchgear room high temp alarm	Improve diagnosis of a loss of switchgear HVAC	0.02%	0.00%	<$1k	>2 x benefit	Screen out	Analysis case HVA determined the maximum benefit to be less than $1k. Not cost beneficial; cost is estimated to exceed twice the benefit.
30	Install containment spray throttle valves	Can extend the time over which water remains in the RWST, when full containment spray flow is not needed.	0.00%	0.00%	$0	>2 x benefit	Screen out	Screening case CSP shows no benefit from this SAMA.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
32	Develop an enhanced containment spray system	Would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal	0.00%	0.00%	$0	>2 x benefit	Screen out	Screening case CSP shows no benefit from this SAMA.
33	Provide a dedicated existing containment spray system	Identical to the previous concept, except that one of the existing spray loops would be used instead of developing a new spray system.	0.00%	0.00%	$0	>2 x benefit	Screen out	Screening case CSP shows no benefit from this SAMA.
34	Install a containment vent large enough to remove ATWS decay heat	Assuming injection is available, would provide alternative decay heat removal in an ATWS	4.9%	1.6%	$90k	>2 x benefit	Screen out	Screening case DHR determined the maximum benefit to be less than $90k. Not cost beneficial; cost is estimated to exceed twice the benefit.
35	Install a filtered containment vent to remove decay heat	Assuming injection is available (non-ATWS sequences), would provide alternate decay heat removal with the released fission products being scrubbed.	4.9%	5.5%	$135k	>2 x benefit	Screen out	Screening case DHR shows the maximum possible benefit of a containment vent as $90k. Screening case SCB shows the maximum possible benefit of the filtering of the fission products in the containment (all non-isolation releases) to be $45k. The combined benefit is $135k. Not cost beneficial; cost is estimated to exceed twice the benefit.
36	Install an unfiltered hardened containment vent	Provides an alternate decay heat removal method (non-ATWS), which is not filtered	4.9%	1.6%	$90k	>2 x benefit	Screen out	Screening case DHR determined the maximum benefit to be less than $90k. Not cost beneficial; cost is estimated to exceed twice the benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
37	Create/enhance hydrogen ignitors with independent power supply.	Use either a new, independent power supply, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies such as the security system diesel. Would reduce hydrogen detonation at lower cost.	0.00%	0.02%	$1k	>2 x benefit	Screen out	Analysis case HYD determined the maximum benefit of eliminating containment failure due to hydrogen burns to be less than $1k. Not cost beneficial; cost is estimated to exceed twice the benefit.
38	Create a passive hydrogen ignition system	Reduce hydrogen detonation potential without requiring electric power	0.00%	0.02%	$1k	>2 x benefit	Screen out	Analysis case HYD determined the maximum benefit of eliminating containment failure due to hydrogen burns to be less than $1k. Not cost beneficial; cost is estimated to exceed twice the benefit.
39	Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris	A molten core escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a meltthrough.	0.00%	100%	$1.6 million	>2 x benefit	Screen out	The baseline analysis shows a maximum possible benefit of removing all offsite releases to be $1.64 million. It is judged that this SAMA would likely have a cost an order of magnitude larger than this possible benefit. Not cost beneficial; cost is estimated to exceed twice the benefit.
40	Create a water cooled rubble bed on the pedestal	This rubble bed would contain a molten core dropping onto the pedestal, and would allow the debris to be cooled.	0.00%	100%	$1.6 million	>2 x benefit	Screen out	The baseline analysis shows a maximum possible benefit of removing all offsite releases to be $1.64 million. It is judged that this SAMA would likely have a cost an order of magnitude larger than this possible benefit. Not cost beneficial; cost is estimated to exceed twice the benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
42	Enhance fire protection system and/or standby gas treatment system hardware and procedures	Improve fission product scrubbing in severe accidents	0.00%	4.9%	$45k	>2 x benefit	Screen out	Screening case SCB shows the maximum possible benefit of the filtering of the fission products in the containment to be $44,800. It is judged that this SAMA would be at a greater cost than this benefit when all necessary hardware and procedural changes are included. Not cost beneficial; cost is estimated to exceed twice the benefit.
43	Create a reactor cavity flooding system	Would enhance debris coolability, reduce core concrete interaction and provide fission product scrubbing	0.00%	0.00%	$0	>2 x benefit	Screen out	Analysis case DEB found no benefit in the SPS level 2 analysis for flooding the reactor cavity. Not cost beneficial; cost is estimated to exceed twice the benefit.
44	Creating other options for reactor cavity flooding	Flood cavity via systems such as diesel driven fire pumps	0.00%	0.00%	$0	>2 x benefit	Screen out	Analysis case DEB found no benefit in the SPS level 2 analysis for flooding the reactor cavity. Not cost beneficial; cost is estimated to exceed twice the benefit.
46	Provide a core debris control system	Would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and containment shell.	0.00%	0.00%	$0	>2 x benefit	Screen out	This failure mode was not found to be a concern in the SPS level 2 analysis, so it is judged to have a negligible benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
47	Create a core melt source reduction system (COMSORS)	Place enough glass underneath the reactor vessel such that a molten core falling on the glass would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur (such benefits are theorized in the reference).	0.00%	100%	$1.6 million	>2 x benefit	Screen out	The baseline analysis shows a maximum possible benefit of removing all offsite releases to be $1.64 million. It is judged that this SAMA would likely have a cost an order of magnitude larger than this possible benefit. Not cost beneficial; cost is estimated to exceed twice the benefit.
48	Provide containment inerting capability	Would prevent combustion of hydrogen and carbon monoxide gases	0.00%	0.02%	$1k	>2 x benefit	Screen out	Analysis case HYD determined the maximum benefit of eliminating containment failure due to hydrogen burns to be less than $1k. Not cost beneficial; cost is estimated to exceed twice the benefit.
49	Use fire water spray pump for containment spray	Redundant containment spray method without high cost	0.00%	0.00%	$0	>2 x benefit	Screen out	Screening case CSP shows a no benefit from this SAMA.
50	Install a passive containment spray system	Containment spray benefits at a very high reliability, and without support systems	0.00%	0.00%	$0	>2 x benefit	Screen out	Screening case CSP shows a no benefit from this SAMA.
54	Provide a reactor vessel exterior cooling system.	Potential to cool a molten core before it causes vessel failure, if the lower head can be submerged in water.	0.00%	4.9%	$45k	>2 x benefit	Screen out	Screening case SCB shows the maximum possible benefit of the filtering of the fission products in the containment to be $44,800. This is judged to also be applicable to preventing a molten core from escaping into containment Not cost beneficial; cost is estimated to exceed twice the benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
55	Create another building, maintained at a vacuum to be connected to containment	In an accident, connecting the new building to containment would depressurize containment and reduce any fission product release.	0.00%	100%	$1.6 million	>2 x benefit	Screen out	The baseline analysis shows a maximum possible benefit of removing all offsite releases to be $1.64 million. It is judged that this SAMA would likely have a cost an order of magnitude larger than this possible benefit. Not cost beneficial; cost is estimated to exceed twice the benefit.
61	Use fuel cells instead of lead-acid batteries	Extend DC power availability in a SBO	5.4%	0.8%	$88k	>2 x benefit	Screen out	The System 80+ submittal (References 16 and 17) estimated the cost to be $2 million. The cost to an existing plant would be larger, while the maximum possible benefit calculated in analysis case BCH is only $88k, so this item is screened out. Not cost beneficial; cost is estimated to exceed twice the benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
64	Alternate battery charging capability	Provide a portable diesel-driven battery charger.	5.4%	0.8%	$88k	>2 x benefit	Screen out	Analysis case BCH determined the maximum benefit of extended battery life during an accident to be $88k. The total battery load of the DC emergency buses during a four-hour SBO event would require a 50KW battery charger. A portable unit with appropriate disconnects on the batteries for hook up during full power operation could be installed. The hookup would need to be brought out the alleyways where the diesel would be located when needed. Temporary cables would also be provided. Total cost for the diesel and plant modifications for its use $1.5-3M. Not cost beneficial; cost is estimated to exceed twice the benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
69	Develop procedures to repair or change out failed 4KV breakers	Offers a recovery path from a failure of breakers that perform transfer of 4.16 kV non-emergency buses from unit station service transformers to system station service transformers, leading to loss of emergency AC power (i.e., in conjunction with failures of the diesel generators).	1.9%	2.0%	$62k	>2 x benefit	Screen out	The concept of capturing significant benefit through generation of a procedure is not realistic because the maintenance crews are already trained on the plant procedures for failed breakers. Therefore, the only portion of this SAMA given merit is the hardware portion (i.e. prestaged replacement breakers). Analysis case 4kV determined the maximum benefit to be $88k if half of all 4kV breaker failures could be replaced in the timeframe considered in the PRA. The cost would be much greater than the actual benefit in order to have the many necessary breakers prestaged for this procedure to be effective. Not cost-beneficial; cost of purchasing, sheltering, and maintaining multiple prestaged 4kV breakers would exceed twice the benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
70	Emphasize steps in recovery of offsite power after a SBO.	Reduced human error probability of offsite power recovery.	1.8%	0.5%	$33k	>2 x benefit	Screen out	Analysis case OPR determined the maximum benefit to be less than $33k. The case was calculated using a 25% reduction in offsite power non-recovery terms. It is judged that this benefit is very optimistic given that training is already provided for offsite power recovery, and the fact that failure to recovery offsite power is likely to be governed by actual failures in the grid and not personnel failure. Not cost beneficial; cost is estimated to exceed twice the true obtainable benefit.
77	Provide a connection to alternate offsite power source (the Gravel Neck fossil units)	Increase offsite power redundancy	5.5%	1.5%	$105k	>2 x benefit	Screen out	Analysis case OSP determined the maximum benefit to be $105k. Assuming that the switchyard has been incapacitated, then a weather-proof duct bank would need to be installed. The duct band would extend nearly ¾ of a mile and traverse under the Intake Canal for the plant. Switchgear would need to be provided at each end to disconnect from the normal sources and align the C/T to the station buses. Total cost would be $2-5M. Not cost beneficial; cost is estimated to exceed twice the benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
81	Alter electric power dependency to BC and CC SW valves	These valves require closing after a LOOP	0.7%	0.5%	$17k	>2 x benefit	Screen out	Analysis case BCC determined the maximum benefit to be $17k. The least expensive option would be to replace the BC and CC isolation valves with AOVs of a fail close design. Total cost to replace the operators, and install air lines, SOVs, etc. would be $900K-1.5M. Not cost beneficial; cost is estimated to exceed twice the benefit.
82	Relocate transfer buses to different rooms	All of the transfer buses are located within the same room, which results in a high CDF fire sequence.	5.0%	0.7%	$41k	>2 x benefit	Screen out	Analysis case RTB determined the maximum benefit to be $41k. Not cost beneficial; cost is estimated to exceed twice the benefit.
83	Put a fast acting MG output breaker on both units	With a fast acting breaker, a turbine runback would be possible, reducing the likelihood of a reactor trip in some cases.	0.1%	0.04%	$3k	>2 x benefit	Screen out	Analysis case MGB determined the maximum benefit to be $3k. Not cost beneficial; cost is estimated to exceed twice the benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
86	Improved SGTR coping abilities	Improved instrumentation to detect SGTR, or additional systems to scrub fission product releases.	2.8%	27%	$256k	>2 x benefit	Screen out	Screening case SGI determined the maximum benefit to be 256k. This SAMA would involve the installation of numerous control circuits within the racks. Existing radiation alarms could be used to generate the high radiation signal. Close signals would be sent to the affected SG PORV, MSTV and Bypass valve, SG Blowdown Trip Valves and to the Terry Turbine steam supply valves (currently a manual valve but the valve would be changed to an AOV or MOV). Auto close to the auxiliary feedwater pumps would not be included to allow the operator time to assure that the SG had at least an 11% level before securing AFW. The mod would include the changeout of the Terry Turbine steam supply valves with control circuits to the racks and control room, instrumentation feeds from an existing rad monitor to the racks, appropriate annunciation in the control room to indicate the automatic action (including an automatic reactor trip) and wiring mods in the racks to the aforementioned components. Total cost would be $1.5-3M. Not cost beneficial; cost is estimated to exceed twice the benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
88	Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift	SGTR sequences would not have a direct release pathway	5.7%	60%	$576k	>2 x benefit	Screen out	Screening case SGR shows a maximum possible benefit of removing all SGTR to be $576k. It is judged that this SAMA would likely have a cost an order of magnitude larger than this possible benefit. Not cost beneficial; cost is estimated to exceed twice the benefit.
89	Replace steam generators with new design	Lower frequency of SGTR	5.7%	60%	$576k	>2 x benefit	Screen out	Screening case SGR shows a maximum possible benefit of removing all SGTR to be $576k. It is judged that this SAMA would likely have a cost an order of magnitude larger than this possible benefit. Not cost beneficial; cost is estimated to exceed twice the benefit.
101	Ensure all ISLOCA releases are scrubbed	Would scrub ISLOCA releases. One suggestion was to plug drains in the break area so the break point would cover with water.	0.00%	5.3%	$40k	>2 x benefit	Screened out	Analysis case ISS shows a maximum possible benefit of this SAMA to be $40k. Assuming the break of concern is in the Safeguards building, a firewater line would be added to flood this area. The line would be remotely operated from the control room. The line would run from the main firewater header to a discharge point in the Safeguards building. The cost is estimated at $125k. Cost and benefit are approximately equal. Item is not screened out.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
103	Add a check valve downstream of the LHSI pumps on the cold leg injection line.	The ISLOCA frequency is dominated by the LHSI injection lines to the cold legs, which have 2 check valves each. Adding another check valve in the common injection line would essentially eliminate the frequency of the ISLOCA sequence through these pathways. However, a single check valve in the common line would create a single failure point for the system. Either a redundant line would have to be added with a check valve in each, or add a check valve to each of the 3 cold leg injection paths.	4.3%	30%	$253k	>2 x benefit	Screen out	Analysis case ISL shows a maximum possible benefit of removing all ISLOCA to be $253k. 3 check valves per unit can be added inside containment. There is an enduring cost associated with testing these check valves. Current testing is critical path, expensive and dose intensive. Present value cost of installing the mods and performing the future testing is $750K-1.25M. Not cost beneficial; cost is estimated to exceed twice the benefit.
111	Install accumulators for turbine driven AFW pump flow control valves	Provide control air accumulators for the turbine driven AFW flow control valves, the motor driven AFW pressure control valves, and S/G PORVs. This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOP.	0.1%	0.04%	$4k	>2 x benefit	Screen out	Screening case FWS shows the maximum possible benefit to be $4k. Not cost beneficial; cost is estimated to exceed twice the benefit.
115	Provide portable generators to be hooked in to the turbine driven AFW, after battery depletion	Extend AFW availability in a SBO (assuming the turbine-driven AFW requires DC power)	0.1%	0.04%	$4k	>2 x benefit	Screen out	Screening case FWS shows the maximum possible benefit to be $4k. Not cost beneficial; cost is estimated to exceed twice the benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
122	Create passive secondary side coolers	Provide a passive heat removal loop with a condenser and heat sink. Would reduce CDF from the loss of feedwater.	12.8%	17.2%	$490k	>2 x benefit	Screen out	Screening case FDW shows the maximum possible benefit as $490k. It is judged that this SAMA would likely be an order of magnitude greater than this benefit. Not cost beneficial; cost is estimated to exceed twice the benefit.
123	Automate air bottle swap for S/G PORVs	Manual action is required to swap air source to the air bottles. Automatic swap on low pressure would eliminate the operator action.	0.00%	0.03%	<$1k	>2 x benefit	Screen out	Analysis case SGP shows the maximum possible benefit to be less than $1k. Not cost beneficial; cost is estimated to exceed twice the benefit.
124	Condenser dump after SI	Utilize bypass around the main steam trip valves to use the condenser dump after an SI (the PRA assumes the function can not be recovered after an SI signal)	2.2%	0.01%	$33k	>2 x benefit	Screen out	Analysis case CND shows the maximum possible benefit to be $33k. Not cost beneficial; cost is estimated to exceed twice the benefit.
125	Provide capability for diesel driven, low pressure vessel makeup	Extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., firewater)	5.0%	0.01%	$76k	>2 x benefit	Screen out	Analysis case LHI shows the benefit to be $76k. The total cost would include adding a line from the firewater header, a post indicator valve in the yard and SR double isolation valves to the connection with the LHSI system. Total cost would be $350-600K. Not cost beneficial; cost is estimated to exceed twice the benefit.

Table 4-6 (continued)

Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
126/127	Provide an additional high pressure injection pump with independent diesel	Reduce frequency of core melt from small LOCA sequences, and from SBO sequences.	3.5%	2.1%	$89k	>2 x benefit	Screen out	Analysis case HPI shows the maximum possible benefit to be $89k. Not cost beneficial; cost is estimated to exceed twice the benefit.
145/146	Install MG set trip breakers in control room	Provides trip breakers for the motor generator sets in the control room. Currently, at Watts Bar, an ATWS would require an immediate action outside the control room to trip the MG sets. Would reduce ATWS CDF	0.01%	0.00%	<1k	>2 x benefit	Screen out	Screening case ATW shows the maximum possible benefit to be less than $1k. Not cost beneficial; cost is estimated to exceed twice the benefit.
154	Create/enhance reactor coolant system depressurization ability	Either with a new depressurization system, or with existing PORVs, head vents and secondary side valve, RCS depressurization would allow low pressure ECCS injection. Even if core damage occurs, low RCS pressure alleviates some concerns about high pressure melt ejection.	0.00%	0.00%	$0	>2 x benefit	Screen out	The SPS Level 2 analysis shows that high pressure melt ejection is not a threat to containment failure. SPS procedures already direct depressurization in the appropriate Level 1 sequences. Analysis case DEB shows that there is no benefit in the Level 2 analysis for low pressure injection after core damage. Therefore, revision to existing procedures or creation of a new system would not be estimated to provide any benefit.

Table 4-6 (continued)
Summary of Surry Power Station SAMAs Considered in Benefit/Cost Analysis [a]

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate and Basis for Conclusion
158	Secondary side guard pipes up to the MSIVs.	Would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. Would also guard against or prevent consequential multiple SGTR following a main steam line break event.	0.00%	0.00%	$0	>2 x benefit	Screen out	Screening case SLB shows there is an inconsequential benefit for MSLB SAMAs, so this item is screened out. Not cost beneficial; cost is estimated to exceed twice the benefit.
159	Digital large break LOCA protection	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (a leak before break).	3.3%	0.01%	$25k	>2 x benefit	Screen out	Analysis case LLO shows a benefit of $25k for this SAMA, which assumed a reduction in large LOCA frequency of 25%. It is judged that the cost of such instrumentation would be many times greater than $25k to be able to achieve this benefit. Not cost beneficial; cost is estimated to exceed twice the benefit.

a. Source: Appendix G, Table G-2-2.

4.21 References

Ref. 4.0-1 U.S. Nuclear Regulatory Commission. 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS).* Volumes 1 and 2. NUREG-1437. Washington, DC.

Ref. 4.0-2 U.S. Nuclear Regulatory Commission. 1996. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses." *Federal Register*. 61, No. 109. June 5.

Ref. 4.0-3 U.S. Nuclear Regulatory Commission. 1999. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*; Section 6.3, "Transportation" and Table 9-1, "Summary of findings on NEPA issues for license renewal of nuclear power plants." NUREG-1437. Vol. 1, Addendum 1. Washington, DC.

Ref. 4.2-1 Virginia Administrative Code, Title 9 – Environment, Agency 25 – State Water Control Board, Chapter 31 – Virginia Pollutant Discharge Elimination System (VPDES) Permit Regulation, Section 60 – Effect of a permit, Paragraph A.1 (9 VAC25-31-60.A.1). Available at http://leg1.state.va.us/cgibin/legp504.exe?000+reg+9vac25-31-220. Accessed July 11, 2000.

Ref. 4.2-2 Virginia Electric and Power Company. 1980. *Surry Power Station – Units 1 and 2; Cooling Water Intake Studies*. Submitted to Virginia State Water Control Board.

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Ref. 4.4-2 Memorandum, Paylor to Seeley. 1996. *Reissuance of VPDES Permit No. VA0004090, Surry Power Station.* Surry, VA.

Ref. 4.5-1 Commonwealth of Virginia Department of Environmental Quality. 1999. Permit to Withdraw Ground Water. Permit Number GW0003900 for Surry Nuclear Power Plant Water System.

Ref. 4.5-2 Holland, M. A. 1999. "Annual Report of Water Withdrawal Regarding Surry Power Station for Calendar Year 1998." Virginia Power. Richmond, VA.

Ref. 4.5-3 Holland, M. A. 1998. "Annual Report of Water Withdrawal Regarding Surry Power Station for Calendar Year 1997." Virginia Power. Richmond, VA.

Ref. 4.5-4 Holland, M. A. 1997. "Annual Report of Water Withdrawal Regarding Surry Power Station for Calendar Year 1996." Virginia Power. Richmond, VA.

Ref. 4.5-5 Holland, M. A. 1996. "Annual Report of Water Withdrawal Regarding Surry Power Station for Calendar Year 1995." Virginia Power. Richmond, VA.

Ref. 4.5-6 Belsches, B. R. 1995. "Annual Report of Water Withdrawal Regarding Surry Power Station for Calendar Year 1994." Virginia Power. Richmond, VA.

Ref. 4.5-7 Belsches, B. R. 1994. "Annual Report of Water Withdrawal Regarding Surry Power Station for Calendar Year 1993." Virginia Power. Richmond, VA.

Ref. 4.5-8 Marshall, B. M. 1993. "Annual Report of Water Withdrawal Regarding Surry Power Station for Calendar Year 1992." Virginia Power. Richmond, VA.

Ref. 4.5-9 James, D. L. Virginia Power. 2000. "Surry/Gravel Neck Ground Water Data." Email to M. Holland and T. Banks, Virginia Power, and K. Patterson, TtNUS. March 3, 2000.

Ref. 4.5-10 Walton, W.C. 1987. *Groundwater Pumping Tests Design and Analysis*. Lewis Publishers, Inc. Chelsea, MI.

Ref. 4.5-11 McFarland, E. R. 1999. *Design, Revisions and Considerations for Continued Use of a Ground-Water-Flow Model of the Coastal Plain Aquifer System in Virginia*. U.S.G.S. Document No. WRIR 98-4085. Available at http://va.water.usgs.gov/online_pubs/WRIR/98-4085/g-wfmcpasys_va.html.

Ref. 4.5-12 Heath, R. C. 1982. *Basic Ground Water Hydrology*. U.S. Geological Survey Water Supply Paper 2220. U.S. Government Printing Office, Washington, DC.

Ref. 4.13-1 National Electrical Safety Code®. 1997 Edition. Published by the Institute of Electrical and Electronics Engineers. August.

Ref. 4.15-1 Fetter, C. W., Jr. 1980. *Applied Hydrogeology.* Charles E. Merrill Publ. Co. Columbus, OH.

Ref. 4.15-2 Newport News Economic Development Authority. 2000. City of Newport News Demographics. Available at http://www.asite4u.org/demo/1.html. Accessed January 6, 2000.

Ref. 4.17-1 King J. 2000. Surry County information. Surry County Administration. Personal communication with W. Craig, TtNUS. January 5.

Ref. 4.18-1 Pauley, J. 2000. Level of Service Classification for Roads in the Vicinity of Surry Station. Personal communication with Y. F. Abernethy, TtNUS. July 6.

Ref. 4.20-1 U.S. Nuclear Regulatory Commission. 1997. "Regulatory Analysis Technical Evaluation Handbook." NUREG/BR-0184. Washington, DC.

Ref. 4.20-2 Leary, J. 2000. "Surry Severe Accident Mitigation Alternative (SAMA) Assessment." Calculation SM-1256. Scientech, Inc.

Ref. 4.20-3 U.S. Nuclear Regulatory Commission. 1995. "Reassessment of NRC's Dollar Per Person-Rem Conversion Factor Policy." NUREG-1530.

Ref. 4.20-4 Matras, M. G. 2000. "MACCS2 Model For Surry Level 3 Application." Calculation SM-1241. Scientech, Inc.

5.0 ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

5.1 Discussion

NRC Input

"...The environmental report must contain any new and significant information regarding the environmental impacts of license renewal of which the applicant is aware." 10 CFR 51.53(c)(3)(iv)

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants and provides for license renewal, requiring a license renewal application that includes an environmental report (10 CFR 54.23). NRC regulations, 10 CFR 51, prescribe the environmental report content and identify the specific analyses the applicant must perform. In an effort to make the environmental review focussed and efficient, NRC has resolved most of the environmental issues generically and only requires an applicant's analysis of the remaining issues.

While NRC regulations do not require an applicant's environmental report to contain analyses of the impacts of those environmental issues that have been generically resolved (termed "Category 1") [10 CFR 51.53(c)(3)(i)], the regulations do require that an applicant identify any new and significant information of which the applicant is aware [10 CFR 51.53(c)(3)(iv)]. The purpose of this requirement is to alert the NRC staff to such information, so the staff can determine whether to seek the Commission's approval to waive or suspend application of the rule with respect to the affected generic analysis. NRC has explicitly indicated, however, that an applicant is not required to perform a site-specific validation of conclusions NRC made for Category 1 issues in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (Ref. 5.1-1, page C9-13, Concern Number NEP.015) because the NRC has concluded that, in all cases, the impacts would be small.

Dominion expects that new and significant information would include:

- Information that identifies a significant environmental issue not covered in the GEIS and codified in the regulation, or
- Information that was not covered in the GEIS analyses and that leads to an impact finding different from that codified in the regulation.

NRC requires license renewal applicants to provide NRC with input, in the form of an environmental report, that NRC will use to meet National Environmental Policy Act (NEPA) requirements as they apply to license renewal (10 CFR 51.10). NEPA authorizes the Council on Environmental Quality (CEQ) to establish implementing regulations for federal agency use. CEQ guidance provides that federal agencies should prepare environmental impact statements for actions that would significantly affect the environment (40 CFR 1502.3), focus on significant environmental issues (40 CFR 1502.1), and eliminate from detailed study issues that are not significant [40 CFR 1501.7(a)(3)]. The CEQ guidance includes a lengthy definition of "significantly" that requires consideration of the context of the action and the intensity or severity of the impact(s) (40 CFR 1508.27). Although NRC does not specifically define the term "significant", Dominion used the guidance available in CEQ regulations to establish significance. Based on this guidance and the definitions of small, moderate, and large impacts provided by NRC, Dominion expects that moderate or large impacts would be significant. Chapter 4 presents the NRC definitions of "moderate" and "large" impacts.

Dominion implemented an assessment process for new and significant information during preparation of the license renewal application for Surry Power Station. The process was directed by the License Renewal Project Environmental Lead and included the following actions: (1) interviews with Dominion subject experts on information related to the conclusions in the GEIS as they relate to SPS, (2) review of documents related to environmental issues at SPS, (3) consultations with state and federal agencies to determine if the agencies had concerns not addressed in the GEIS, (4) a review of internal procedures for reporting to the NRC events that could have environmental impacts, and (5) credit for the oversight provided by inspections of plant facilities by state and federal regulatory agencies.

As a result of this assessment, Dominion is aware of no new and significant information regarding the environmental impacts of Surry Power Station Units 1 and 2 license renewal.

5.2 References

Ref. 5.1-1 U.S. Nuclear Regulatory Commission. 1996. *Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response.* Volumes 1 and 2. NUREG-1529. Washington, DC.

6.0 SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 License Renewal Impacts

Dominion has reviewed the environmental impacts of renewing the Surry Power Station Units 1 and 2 (SPS) operating licenses and has concluded that all of the impacts would be small and would not require mitigation. This environmental report documents the basis for Dominion's conclusion. Chapter 4 incorporates by reference U.S. Nuclear Regulatory Commission (NRC) findings for the 51 Category 1 issues that apply to SPS (Table 4-2). The rest of Chapter 4 analyzes Category 2 issues, all of which are either not applicable or have impacts that would be small. Table 6-1 identifies the impacts that SPS license renewal would have on resources associated with Category 2 issues.

6.2 Mitigation

NRC Input

"The report must contain a consideration of alternatives for reducing adverse impacts…for all Category 2 license renewal issues…." 10 CFR 51.53(c)(3)(iii)

"The environmental report shall include an analysis that considers and balances…alternatives available for reducing or avoiding adverse environmental effects…." 10 CFR 51.45(c) as incorporated by 10 CFR 51.53(c)(2) and 10 CFR 51.45(c)

All impacts of license renewal are small and would not require mitigation. Current operations include mitigation activities that would continue during the term of the license renewal. Dominion performs routine mitigation and monitoring activities associated with environmental permits to ensure the safety of workers, the public, and the environment. These activities include the radiological environmental monitoring program, continuous emission monitoring, monitoring of aquatic biota that could be affected by SPS operation, effluent chemistry monitoring, and effluent toxicity testing. Dominion is monitoring its groundwater use to determine if it impacts any pre-existing users and will mitigate any impacts identified to pre-existing users. In addition, Dominion is developing a groundwater conservation and management plan that will be submitted to the Commonwealth in 2009.

6.3 Unavoidable Adverse Impacts

NRC Input

The environmental report shall discuss any "...adverse environmental effects which cannot be avoided should the proposal be implemented..." 10 CFR 51.45(b)(2) as adopted by 10 CFR 51.53(c)(2)

This environmental report adopts by reference NRC findings for applicable Category 1 issues, including discussions of any unavoidable adverse impacts (Table 4-2). Dominion examined 21 Category 2 issues and identified the following unavoidable adverse impacts of license renewal:

- Some fish are impinged on the Ristroph traveling screens at the intake structures. Based on the results of the Clean Water Act 316(b) Demonstration (Ref. 6.3-1, pg. 8), approximately 94 percent of the fish captured on the screens are returned alive to the river.
- Some larval fish and shellfish are entrained at the intake structures. When SPS is operating at full power, the eight circulating water pumps withdraw 1,680,000 gallons per minute of water from the James River for condenser cooling. This flow represents approximately 3 percent of the river flow at SPS associated with tidal movement, or the total volume of water that moves upriver with flood tides and downriver with ebb tides (Ref. 6.3-1, pg. 9). Based on studies conducted in the 1970s (Ref. 6.3-1, Sec. 8.0), the SPS cooling water intake has had no detectable impact upon fish populations in the vicinity of SPS. Two species with little or no commercial value, the bay anchovy and the naked goby, made up 91 percent of all ichthyoplankton entrained from 1976 through 1978 (Ref. 6.3-1, pg. 97). Fluctuations in the abundance of these and other species were attributed to salinity differences between years.
- For purposes of analysis, Dominion assumed that license renewal would require 60 additional staff, although Dominion does not expect to need that many additional staff. The addition of 60 households to the three counties and one metropolitan area in which majority of current SPS workers reside would result in impacts to housing availability, transportation infrastructure, and public utilities that may be considered unavoidable and adverse, but are not significant.

6.4 Irreversible and Irretrievable Resource Commitments

NRC Input

The environmental report shall discuss any "...irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented"... 10 CFR 51.45(b)(5) as adopted by 10 CFR 51.53(c)(2)

The continued operation of SPS for the license renewal term would result in irreversible and irretrievable resource commitments, including the following:

- nuclear fuel, which is burned in the reactors and converted to radioactive waste
- the land required to dispose of spent nuclear fuel, low-level radioactive wastes generated as a result of plant operations, and sanitary wastes generated from normal industrial operations
- elemental materials that would become radioactive
- materials used for the normal industrial operations of the plant that cannot be recovered or recycled or that are consumed or reduced to unrecoverable forms.

6.5 Short-Term Use Versus Long-term Productivity of the Environment

NRC Input

The environmental report shall discuss the "...relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity..." 10 CFR 51.45(b)(4) as adopted by 10 CFR 51.53(c)(2)

The current balance between short-term use and long-term productivity at the SPS site was basically set once the units began operating in the 1970s. The Surry Power Station Unit 1 Final Environmental Statement (Ref. 6.5-1, Chapters IV and V) evaluated the impacts of constructing and operating SPS in rural southeastern Virginia. The site was originally part of a privately-owned tract that was timbered for pulpwood and lumber. Much of the land could be returned to the same or similar use after SPS is decommissioned, but those decisions have not been made. Continued operations for an additional 20 years would not alter this conclusion.

TABLES

Table 6-1
Environmental Impacts Related to License Renewal at Surry Power Station Units 1 and 2

No.	Issue	Environmental Impact
	Surface Water Quality, Hydrology, and Use (for all plants)	
13	Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	None. This issue does not apply because SPS does not use cooling ponds or cooling towers.
	Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)	
25	Entrainment of fish and shellfish in early life stages	Small. Dominion has a current VPDES permit which constitutes compliance with CWA Section 316(b) requirements to provide best available technology to minimize entrainment.
26	Impingement of fish and shellfish	Small. Dominion Power has a current VPDES permit which constitutes compliance with CWA Section 316(b) requirements to provide best available technology to minimize impingement.
27	Heat shock	Small. Dominion has a current VPDES permit that grants a thermal variance for SPS discharges to the James River.
	Groundwater Use and Quality	
33	Groundwater use conflicts (potable and service water, and dewatering; plants that use > 100 gpm)	Small. Drawdowns calculated from actual pumping data indicate that the pumping results in a drawdown of less than 0.5 foot at the nearest offsite well.
34	Groundwater use conflicts (plants using cooling towers withdrawing makeup water from a small river)	None. This issue does not apply because SPS does not use cooling towers.
35	Groundwater use conflicts (Ranney wells)	None. This issue does not apply because SPS does not use Ranney wells.

Table 6-1 (continued)
Environmental Impacts Related to License Renewal at Surry Power Station Units 1 and 2

No.	Issue	Environmental Impact
39	Groundwater quality degradation (cooling ponds at inland sites)	None. This issue does not apply because SPS does not use cooling ponds.
	Terrestrial Resources	
40	Refurbishment impacts	No impacts are expected because SPS will not undertake refurbishment.
	Threatened or Endangered Species	
49	Threatened or endangered species	Small. Although bald eagles nest in the area, the operation of SPS does not adversely affect them. The barking treefrog has been observed on the SPS site. No other threatened or endangered species is known to occur at SPS or along its transmission corridors.
	Air Quality	
50	Air quality during refurbishment (nonattainment and maintenance areas)	No impacts are expected because SPS will not undertake refurbishment.
	Human Health	
57	Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	None. This issue does not apply because SPS does not discharge to a small river.
59	Electromagnetic fields, acute effects (electric shock)	Small. The largest modeled induced current under any SPS transmission line would be 5.068 amperes, which exceeds the NESC limit of 5.0 amperes by 1 percent. All SPS lines were constructed prior to the 1977 provision of the code for establishing minimal vertical clearances.

Table 6-1 (continued)
Environmental Impacts Related to License Renewal at Surry Power Station Units 1 and 2

No.	Issue	Environmental Impact
		Socioeconomics
63	Housing impacts	Small. SPS is in a high-population area. Dominion has concluded that housing impacts would be small from 60 new employees.
65	Public services: public utilities	Small. Any increase in public water from 60 new employee households would be an insignificant percentage of the water supplies of the affected communities.
66	Public services: education (refurbishment)	No impacts are expected because SPS will not undertake refurbishment.
68	Offsite land use (refurbishment)	No impacts are expected because SPS will not undertake refurbishment.
69	Offsite land use (license renewal term)	Small. SPS is the dominant source of tax revenue for Surry County. However, since construction of the plant, Surry County has not experienced large land-use changes. License renewal would have a continued positive effect on the county, but would not induce changes to local land use or development.
70	Public services: transportation	Small. Any additional employees would be fewer than the temporary outage workforce of 700 additional people. Access roads are adequate for the increase in traffic resulting from the outages. For this reason, Dominion concludes that there would be no transportation impacts.
71	Historic and archaeological resources	Small. Continued operation of SPS does not require construction at the site or new transmission lines. Therefore, Dominion concludes that it would not adversely affect historic or archaeological resources.

Table 6-1 (continued)
Environmental Impacts Related to License Renewal at Surry Power Station Units 1 and 2

No.	Issue	Environmental Impact
		Postulated Accidents
76	Severe accidents	Small. The benefit/cost analysis identified no severe accident mitigation alternatives that would avert public risk.[a]

a. NRC determined that risk of severe accidents is small for all plants (10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 76), but that alternatives to mitigate severe accidents must be considered for plants that have not considered such alternatives.

6.6 References

Ref. 6.3-1 Virginia Electric and Power Company. 1980. *Surry Power Station – Units 1 and 2 Cooling Water Intake Studies.* Submitted to Virginia Water Control Board.

Ref. 6.5-1 U.S. Atomic Energy Commission. 1972. *Final Environmental Statement related to Operation of Surry Power Station Unit 1.* Virginia Electric and Power Company. Docket No. 50-280.

7.0 ALTERNATIVES TO THE PROPOSED ACTION

NRC Input

The environmental report shall discuss "Alternatives to the proposed action...." 10 CFR 51.45(b)(3), as adopted by reference at 10 CFR 51.53(c)(2).

"...The report is not required to include discussion of need for power or economic costs and benefits of ... alternatives to the proposed action except insofar as such costs and benefits are either essential for a determination regarding the inclusion of an alternative in the range of alternatives considered or relevant to mitigation...." 10 CFR 51.53(c)(2).

"While many methods are available for generating electricity, and a huge number of combinations or mixes can be assimilated to meet a defined generating requirement, such expansive consideration would be too unwieldy to perform given the purposes of this analysis. Therefore, NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable…" (Ref. 7.0-1, Section 8.1).

"…The consideration of alternative energy sources in individual license renewal reviews will consider those alternatives that are reasonable for the region, including power purchases from outside the applicant's service area.…" (Ref. 7.0-2, Section II.H).

Chapter 7 evaluates alternatives to Surry Power Station Units 1 and 2 (SPS) license renewal. The chapter identifies actions that could be necessary to meet system generating needs now provided by SPS and associated environmental impacts, if the U.S. Nuclear Regulatory Commission (NRC) did not renew the plant operating licenses. The chapter also identifies alternative actions that Dominion has evaluated, but determined to be unreasonable, and presents the information upon which Dominion based that decision.

Dominion divided its alternatives discussion into two categories, "no action" and "alternatives that meet system generating needs." In determining the level of detail and analysis necessary for each category, Dominion relied on the NRC decision-making standard for license renewal:

> "…the NRC staff, adjudicatory officers, and Commission shall determine whether or not the adverse environmental impacts of license renewal are so great that preserving the option of license renewal for energy planning decision makers would be unreasonable." [10 CFR 51.95(c)(4)].

Dominion determined that as long as the environmental report provides sufficient information to clearly indicate whether an alternative would have a smaller, comparable, or greater environmental impact than the proposed action, the document would support NRC decision making. Providing additional detail or analysis would serve no function if it would only bring to light more adverse impacts of alternatives to license renewal. This approach is consistent with regulations of the Council on Environmental Quality, which specify that the consideration of alternatives (including the proposed action) should enable reviewers to evaluate their comparative merits (40 CFR 1500-1508). Dominion believes that Chapter 7 provides sufficient detail about alternatives to establish the basis for necessary comparisons to the Chapter 4 discussion of impacts from the proposed action.

In characterizing environmental impacts from alternatives, Dominion has used the same definitions of "small", "moderate", and "large" that the Chapter 4 Introduction presents.

7.1 No-Action Alternative

Dominion is using the "no-action" alternative to refer to a scenario in which the NRC does not renew the SPS operating licenses. Components of this alternative include replacing the generating capacity of SPS and decommissioning the facility, as described below.

Presently, SPS annually provides approximately 12 terawatts hours of electricity (a terawatt hour is one billion kilowatt hours). This is approximately 17 percent of the power that Dominion provides to its more than 2 million home and business customers (Ref. 7.1-1). Dominion believes that any alternative would be unreasonable if it did not include replacing this capacity. Replacement could be accomplished by (1) building new generating capacity, (2) purchasing power from outside the Dominion system, or (3) reducing power requirements through demand reduction. Section 7.2.1 describes each of these possibilities in detail, and Section 7.2.2 describes environmental impacts from feasible alternatives.

The Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS, Ref. 7.0-1, pg. 7-1) defines decommissioning as the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license. NRC-evaluated decommissioning options include immediate decontamination and dismantlement (DECON), or safe storage of the stabilized and defueled facility for a period of time (SAFSTOR), followed by decontamination and dismantlement. Regardless of the option chosen, decommissioning must be completed within a 60-year period. Under the no-action alternative, Dominion would continue operating SPS until the current licenses expired, then initiate decommissioning activities in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of an example reactor (the "reference" pressurized-water reactor is the 1,175-megawatt (MW) Trojan Nuclear Plant reactor). This description is comparable to decommissioning activities that Dominion would conduct at SPS, but Dominion notes that the reference unit size is larger than the SPS unit size (855 MW).

As the GEIS notes, NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts include: occupational and public dose; impacts of waste management; impacts to air and water quality; and ecological, economic, and socioeconomic impacts. NRC indicated (Ref. 7.1-2, pg. 4-15) that the environmental effects of greatest concern (i.e., radiation dose and releases to the environment) are substantially less than the same effects resulting from reactor operations. Dominion adopts by reference the NRC conclusions regarding environmental impacts of decommissioning.

Dominion notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. Dominion will have to decommission SPS regardless of the NRC decision on license renewal; license renewal would only postpone decommissioning for an additional 20 years. The NRC has established in the GEIS that the timing of decommissioning operations does not substantially influence the environmental impacts of decommissioning. Dominion adopts by reference the NRC findings (10 CFR 51 Appendix B, Table B-1, Decommissioning) to the effect that delaying decommissioning until after the renewal term would have small environmental impacts. The discriminators between the proposed action and the no-action alternative lie within the choice of generation replacement options to be part of the no-action alternative. Section 7.2.2 analyzes the impacts from these options.

Dominion concludes that the decommissioning impacts under the no-action alternative would not be substantially different from those occurring following license renewal as identified in the GEIS (Ref. 7.0-1) and the decommissioning generic environmental impact statement (Ref. 7.1-2). These impacts would be temporary and would occur at the same time as the impacts from meeting system generating needs.

7.2 Alternatives That Meet System Generating Needs

Decisions regarding reasonable alternatives for meeting electrical demands in Virginia are made primarily by two entities, utilities and the Virginia State Corporation Commission. The current mix of power generation options in Virginia is one indicator of what these entities believe are feasible alternatives within the Commonwealth. In 1996, Virginia's electric utility industry had a total generating capability of 14.8 gigawatts-electric (a gigawatt is one million kilowatts). This capability includes units fueled by coal (34 percent); nuclear (23 percent); oil (15 percent); gas (7 percent); and hydroelectric (21 percent) (Ref. 7.2-1, Figure 1). Virginia utilities do not have significant generating capacity in other technologies such as geothermal, biomass, wind, solar thermal, and photovoltaic. Approximately 3.6 gigawatts electric (20 percent of the Commonwealth's generating capability) was from nonutility sources (Ref. 7.2-1, Table 4). Nonutility generators also use a variety of energy sources.

Based on 1996 Virginia generation data, utility companies provided 56.5 terawatt hours of electricity. Utilities' generation was dominated by coal (49 percent), followed by nuclear (47 percent), gas (2 percent), oil (1 percent), and hydroelectric (1 percent) (Ref. 7.2-1, Figure 2). Approximately 10.5 terawatt hours of electricity (16 percent of the Commonwealth's generation) was provided by nonutility sources (Ref. 7.2-1, Table 5).

The difference between capability and utilization reflects preferential usage. For example, nuclear energy represented 23 percent of utilities' installed capability, but produced 47 percent of the electricity generated by utilities (Ref. 7.2-1, Figures 1 and 2, respectively). This reflects Virginia's preferential reliance on nuclear energy as a base-load generating source. Figures 7-1 and 7-2 illustrate Virginia's utility generating capabilities and utilization, respectively.

Figure 7-3 illustrates the Dominion energy capability mix in 1998. Dominion's generation capability mix differs from the total Commonwealth's utility industry (Ref. 7.2-1, Figure 7-1). In 1998, 33 percent of Dominion's capability was from nuclear. In 1996 (the most recent Commonwealth data available), Dominion's nuclear capability represented 23 percent of the Commonwealth's utility generation capability. Forty-two percent of Dominion's capability in 1998 was from coal; in 1996, 34 percent of the Commonwealth's utility generating capability was from coal. Dominion relied on power purchased from utility and nonutility generators for 19 percent of its energy capability mix in 1998. As of January 1, 1999, Dominion's summer net capacity was 13.7 gigawatts with a nuclear capacity of 3.4 gigawatts, a fossil capacity of 8.7 gigawatts, and a hydroelectric capacity of 1.6 gigawatts. In addition, nonutility generation provided 3.3 gigawatts and purchases from other utilities totaled 1.2 gigawatts, for a combined total summer capacity of 18.2 gigawatts (Ref. 7.2-2, pg. 1).

7.2.1 Alternatives Considered

Technology Choices

Dominion routinely conducts evaluations of alternative generating technologies. The most recent generation expansion options planning study reviews emerging technologies, opportunity fuels, and technology development programs (Ref. 7.2-3). Technologies included advanced fossil conversion, advanced energy systems, renewables, waste fuel systems, and energy storage. The U. S. Rural Electrification Administration recently evaluated alternatives to Dominion-proposed generation capacity construction (Ref. 7.2-4). To summarize, the Rural Electrification Administration evaluation covered the following topics:

- alternatives not requiring new construction (no action, purchase power, and conservation and load modifications)
- alternatives requiring new generation (joint venture, generation, and cogeneration and independent power production)
- alternative generation technologies (combustion turbines, combined cycle, hydroelectric, nuclear, refuse/biomass, and others)
- alternative plant sites
- alternative plant systems.

Based on these and other internal evaluations, Dominion has concluded that feasible alternatives for Dominion system planning purposes include pulverized coal for base-load operations, advanced combustion turbines for peak-load operations, and advanced combined-cycle units for mid- or base-load operations. These conclusions are borne out by the generation utilization information that Section 7.2 introductory text describes: coal and gas are the most heavily utilized non-nuclear generating technologies in Virginia. For purposes of the SPS license renewal environmental report, Dominion has limited its alternatives analysis for new generating capacity to the technologies it considers feasible to replace the large base-load SPS units: pulverized coal-fired units and gas-fired combined-cycle turbines.

Mixture

The NRC indicated in the GEIS that, while many methods are available for generating electricity, and a huge number of combinations or mixes can be assimilated to meet system needs, such expansive consideration would be too unwieldy given the purposes of the alternatives analysis. Therefore, NRC determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation technologies that are technically reasonable and commercially viable (Ref. 7.0-1, pg. 8-1). Consistent with the NRC determination, Dominion has not evaluated mixes of generating sources.

Deregulation

Beginning in 1996, the Commonwealth of Virginia began restructuring the electric utility industry in the state. It is expected to be fully deregulated by 2007. A deregulated market is perceived as having benefits in areas of economic efficiency, allocation of resources, and customer choices. Advances in technology are producing lower-cost, more flexible power generation options (Ref. 7.2-5, paragraphs 4 and 5). For example, Dominion has implemented Project Current Choice, a program under which customers could begin selecting an alternative provider (Ref. 7.2-6).

Nonutility generation has arisen as a principal source of new generating capacity in Virginia, which is the first major source of competition for construction and operation of power plants. The Virginia State Corporation Commission has been generally supportive of a balance between utility construction and purchase from nonutility generators. However, it was reluctant to grant Dominion the authority in 1999 to construct four gas-fired turbine generators that would provide up to 600 MW of power by July 1, 2000. The 1999 Virginia General Assembly enacted the Electric Utility Restructuring Act, which opens the generation market and foresees competition as the primary regulator of the price of electricity. For the law to work as intended, there must be many generators or other suppliers to provide for the needs of customers and these must be willing to compete for business on the basis of price, service, and other factors. The State Corporation Commission "will take all necessary actions to mitigate market power, to ensure that the operation of generating units of incumbent utilities will not inhibit the development of competition within the Commonwealth, ..." (Ref. 7.2-7).

The relationship of economic deregulation of generation and nuclear power is of particular concern. The State Corporation Commission feels that maintenance of the nuclear industry in Virginia is critical from reliability, fuel diversity, and public health and safety perspectives (Ref. 7.2-8, pg. 4).

Based on the issues detailed above, it is not clear that Dominion would be granted the authority to construct new generating units to replace SPS if its licenses were not renewed. However, regardless of what entities constructed and operated the replacement power sources, certain environmental parameters would be constant among replacement power sources. Therefore, it is appropriate and instructive for Dominion to discuss the impacts of reasonable alternatives to the SPS.

Alternatives

The following sections present new systems for fossil-fuel-fired generation (Section 7.2.1.1) and imported power (Section 7.2.1.2) as reasonable alternatives to license renewal. Section 7.2.1.3 discusses reduced demand and presents the basis for concluding that it is not a reasonable alternative to license renewal.

7.2.1.1 Construct and Operate Fossil-Fuel-Fired Generation

Dominion analyzed hypothetical new coal- and gas-fired units at the existing SPS site. This approach could minimize environmental impacts by building on previously disturbed land and by making the most possible use of existing facilities: transmission lines, roads and parking areas, office buildings, and the cooling system.

For comparability, Dominion selected coal- and gas-fired units of equal electric power and equal capacity factors. A scenario of, for example, two 801-MW units could be assumed to replace the 1,602-MW SPS net capacity. However, Dominion's experience indicates that, although customized unit sizes can be built, using standardized sizes is more economical. For example, a manufacturer's standard-sized units include a gas-fired combined-cycle unit of 508 MWe net (GE Frame 7FA) capacity. Dominion evaluated constructing three 508-MW gas-fired units (Table 7-2) and, for comparability, set the net power of the coal-fired units at 508 MW (Table 7-1). Although this provides less capacity than the existing units, it ensures against overestimating environmental impacts from these alternatives. The shortfall in capacity could be replaced by other methods (see Mixture in Section 7.2.1).

It must be emphasized, however, that these are hypothetical scenarios. Dominion does not have plans for such construction at SPS.

Coal-Fired Generation

NRC has evaluated coal-fired generation alternatives for the Calvert Cliffs Nuclear Power Plant (Ref. 7.2-9, Section 8.2.1) and for the Oconee Nuclear Station (Ref. 7.2-10 Section 8.2.1). For Calvert Cliffs, NRC analyzed three 600-MW units. Dominion has reviewed the NRC analysis and believes it to be sound. In defining the SPS coal-fired alternative, Dominion has used site- and Virginia-specific input and has scaled from the NRC analysis, where appropriate.

Table 7-1 presents the basic coal-fired alternative emission control characteristics. Dominion based its emission control technology and percent control assumptions on alternatives that the U.S. Environmental Protection Agency (EPA) has identified as being available for minimizing emissions (Ref. 7.2-11). Coal and limestone (or lime) would be delivered by barge to the existing SPS receiving dock.

Gas-Fired Generation

Dominion's current emphasis on gas-fired generation is evidenced by its construction of 596 MW of gas-fired combustion turbine capacity that became operational in 2000, its application to construct two additional combustion turbines in 2001, and the conversion of Possum Point units to a gas-fired facility. Dominion has chosen to evaluate gas-fired generation, using combined-cycle turbines, because it has determined that the technology is mature, economical, and feasible. Dominion experience indicates that the readily available standard-sized gas-fired units of 508-MW are more economical than customized units. Therefore, Dominion has analyzed 1524 MW of net power, consisting of three 508-MW gas-fired units located on SPS property. Table 7-2 presents the basic gas-fired alternative characteristics. Dominion realizes that gas availability would be questionable. It would require a new dedicated high-pressure 24-inch pipeline from Danville, Virginia. In the winter, it may become necessary for Dominion to operate on fuel oil, which would have higher costs and more emissions than gas.

7.2.1.2 Purchase Power

Dominion has evaluated conventional and prospective power supply options that could be reasonably implemented in the 2000-2009 time period. Virginia Electric and Power Company filed its annual Resource Plan with the North Carolina Commission on September 1, 1999 (Ref. 7.2-15). As outlined in the resource plan, Dominion has firm purchase agreements throughout the forecast period ending in 2009. These firm purchases include a 145-MW purchase agreement with the Southeastern Power Administration and contracts for approximately 3,500 MW of non-utility generation.

These purchases alone would not be sufficient to satisfy the projected future demand. Dominion constructed combustion turbines with a capacity of 596 MW to be operational in the summer of 2000. The Company has sought approval to construct two additional combustion turbine units to be operational in the summer of 2001. Also included in the projection is a savings of 74 MW from the net effect of various demand side management (DSM) programs. The generation shortfall will be made up through purchases from the generation market. Projected purchases from the generation market would begin in 2001 with 318 MW and grow to 1,893 MW in 2009. To increase its capability to import power, Dominion is building a 500-kilovolt (kV) transmission line from the Joshua Falls substation near

Lynchburg to the substation at Ladysmith in Caroline County. This interconnect is expected to be operational by 2001.

Contracts with Southeastern Power Administration and non-utility generators are included in discussions of Dominion's current and future capacity. Other than discussed above, no substantial new capacity or purchases are foreseen in the Dominion network. Therefore, Dominion would require a major increase in purchases (1,602 MW net power to the grid) from the generation market outside the Dominion network to replace SPS. Dominion presumes that the generating technology producing purchased power would be one of those that NRC analyzed in the GEIS. For this reason, Dominion is adopting by reference, as representative of the purchased power alternative, the GEIS description of the alternative generating technologies. Of these technologies, simple-cycle combustion turbines or combined-cycle facilities fueled by natural gas are found to be the most cost-effective. There has been a corresponding decreased incentive for boilers fired by coal or residual oil.

Although purchased power could provide at least part of the replacement power for SPS, Dominion has identified drawbacks to this alternative, including the following:

- The existing power transmission infrastructure currently lacks capacity to import an additional 1,602 MW of power to replace SPS capacity. It would require the construction of at least one additional 500-kV transmission line.
- To ensure its capability to meet customer demands for reliable and affordable power, Dominion limits the amount of power it imports. Under its current power-import restriction, it is unlikely that Dominion could both implement its current plans to increase purchases from the generation market and replace the power generated by SPS with imported power.
- Utility generators providing power to Dominion would need to increase their capacity with new power units. As described above, the most cost-effective alternatives for increasing electric power capacity are simple- cycle combustion turbines or combined-cycle facilities fueled primarily by natural gas. However, existing gas line capacity in Virginia is inadequate to support more gas-fired combustion turbines. Constructing additional pipelines is both time-consuming and expensive.
- Deregulation is expected to be in place by 2007. Under deregulation, non-utility generators could compete directly with utility companies for the generation

market. This is expected to decrease non-utility generators' incentive to provide wholesale power to utility companies.

7.2.1.3 Reduce Demand

Dominion offers the following four DSM programs, which either conserve energy or allow the Company to reduce customers' load requirements during periods of peak demands. The four programs are:

Conservation Program

- Energy Saver Home Plus (in North Carolina only)

Load Management Programs

- Rate Schedule SG -- Standby Generation
- Rate Schedule CS -- Curtailable Service
- Rider J: Interruptible Electric Water Heater Service

Dominion annually projects both the summer and winter peak power (in MW) and annual energy requirements (in gigawatt-hours or GWH) impacts of DSM. The 1999 projections are that, by the year 2007, Dominion will reduce peak power requirements in the summer and winter by 74 and 130 MW, respectively. Energy requirements in the same year would be reduced by 14 GWH, 94 percent of which would be from load management programs.

This represents a decrease in DSM initiatives that have been in effect for the past 30 years. Market conditions which provided the initial support for utility-sponsored conservation and load management efforts during the late 1970s and early 1980s can be broadly characterized by:

- Increasing long-term marginal prices for capacity and energy-production resources
- Forecasts projecting increasing demand for electricity across the nation
- General agreement that the first two conditions would continue for the foreseeable future
- Limited competition in the generation of electricity
- Economies of scale in the generation of electricity which previously supported the construction of large central power plants, and
- Use of average embedded cost as the basis for setting electricity prices within a regulated context.

These market and regulatory conditions are undergoing dramatic changes. The changes, which have significantly impacted the cost-effectiveness of utility-sponsored DSM, can be described as follows:

- A decline in generation costs, due primarily to technological advances that have reduced the cost of constructing new generating units (e.g., combustion turbines), and
- National energy legislation that has encouraged wholesale competition through open access to the transmission grid, as well as state legislation designed to facilitate retail competition.

Consistent with the two points above, the utility planning environment features lower capacity and lower energy prices than during earlier periods, shorter planning horizons, lower reserve margins, and increased reliance on market prices to direct utility resource planning. This, in turn, has greatly reduced the number of cost-effective DSM alternatives.

Other significant changes include:

- Rate design programs that enable customers to make energy choices based on their unique energy needs and costs. An example is Dominion's hourly Real Time Pricing rate. Such rate designs will increasingly replace incentive-driven direct load-control programs.
- The adoption of increasingly stringent national appliance standards for most major energy-using equipment and the adoption of energy efficiency requirements in state building codes. These mandates have further reduced the potential for cost-effective utility-sponsored measures.
- Third parties are increasingly providing energy services and products in competitive markets at prices that reflect their value to the customer. Market conditions can be expected to continue this shift among providers of cost-effective load management.

For these reasons, Dominion determined that the remaining DSM programs, which are primarily directed toward load management, are not an effective substitute for any of its large base-load units operating at high capacity factors, including SPS.

7.2.2 Environmental Impacts of Alternatives

This section evaluates the environmental impacts from generation strategies that Dominion has determined to be reasonable [NEPA] alternatives to SPS license renewal: coal- and gas-fired generation at the SPS site and purchased power.

7.2.2.1 Coal-Fired Generation

The NRC evaluated environmental impacts from coal-fired generation alternatives in the GEIS (Ref. 7.0-1, Section 8.3.9). NRC concluded that construction impacts could be substantial, due in part to the large amount of land required, which could result in natural habitat loss, and also to the large workforce needed. NRC pointed out that siting a new coal-fired plant where a nuclear plant is already located would reduce many construction impacts. NRC identified major adverse impacts from operations to be: human health concerns associated with air emissions; waste generation; and losses of aquatic biota due to cooling water withdrawals and discharges.

The coal-fired alternative that Dominion has defined in Section 7.2.1.1 would be located at the existing SPS site on previously disturbed land, thereby reducing construction impacts. The alternative also would use the existing cooling water system, thereby reducing aquatic impacts from operations. Therefore, Dominion has limited its detailed evaluation to air emissions and associated waste generation in the forms of ash and scrubber waste.

Air Quality

Air quality impacts of coal-fired generation are considerably different from those of nuclear power. A coal-fired plant would emit sulfur oxides, nitrogen oxides, carbon monoxide, and particulate matter (pm), all of which are regulated pollutants. As Section 7.2.1.1 indicates, Dominion has assumed a plant design that would minimize air emissions. Reduced air emissions result from a combination of boiler technology and post-combustion pollutant removal. Dominion estimates the coal-fired alternative emissions to be as follows:

Sulfur oxides = 4,548 tons per year

Nitrogen oxides = 1,185 tons per year

Carbon monoxide = 1,221 tons per year

Particulates:

Total suspended particulates = 261 tons per year

PM_{10} (particulates having a diameter of less than 10 microns) = 60 tons per year

Table 7-3 presents the equations Dominion used to calculate these emissions.

Nationally, emissions of sulfur dioxide and nitrogen oxides from Virginia's generators ranked 20th and 28th, respectively. Emissions of both pollutants increased from 1986 to 1996. Although no Virginia generators were mentioned in Title IV of the Clean Air Act Amendments of 1990, it is likely that Virginia's Department of Environmental Quality will need to design a state implementation plan for reducing groundlevel ozone in response to an October 1998 proposal released by the EPA. The EPA proposal does not mandate which sources must reduce pollution. However, the EPA states that utilities would be one of the most likely sources of nitrogen oxides emissions reductions. Virginia is also part of the Ozone Transport Commission. Each of the 13 states of the Ozone Transport Commission is responsible for: enacting regulations in order to achieve region-wide nitrogen oxides reductions in a consistent, enforceable manner; and allocating its nitrogen oxides Budget Program allowances among nitrogen oxides sources in the state. The targets in this program are all electricity-generating facilities with a rated output of 15 MW or more and large industrial boilers (Ref. 7.2-1, pg. 281).

The Clean Air Act Amendments capped the nation's sulfur dioxide emissions from power plants, and each utility was allocated sulfur dioxide allowances. To be in compliance with the Act, Dominion must hold enough allowances to cover its annual sulfur dioxide emissions. Dominion would have to purchase additional allowances from the open market if it did not have enough surplus allowances to operate an additional fossil-burning plant at the SPS site. Nitrogen oxide emissions are also controlled under the Act, and utilities often have to purchase offsets to remain in compliance. Operation of a coal-fired plant may require that Dominion purchase nitrogen oxide offsets.

NRC did not quantify coal-fired emissions, but implied that air impacts would be substantial. The NRC noted that adverse human health effects from coal combustion have led to important federal legislation in recent years and that public health risks, such as cancer and emphysema, have been associated with coal combustion. The NRC also mentioned global warming and acid rain as potential impacts. Dominion concludes that federal legislation and large-scale concerns, such as global warming and acid rain, are indications of concerns about destabilizing important attributes of air resources. However, sulfur oxides emission allowances, nitrogen oxides emission offsets, low nitrogen oxide burners, overfire air, selective catalytic reduction, fabric filters or electrostatic precipitators, and scrubbers are regulatorily-imposed mitigation measures. As such, Dominion concludes that the coal-fired alternative would have moderate impacts on air quality; the impacts would be clearly noticeable, but would not destabilize air quality in the area.

Waste Management

Dominion concurs with the GEIS assessment that the coal-fired alternative would generate substantial solid waste. The coal-fired plant would annually consume approximately 4,884,600 tons of coal having an ash content of 10.7 percent (Tables 7-3 and 7-1). After combustion, most (99.9 percent) of this ash, approximately 522,130 tons per year, would be collected and disposed of onsite. In addition, approximately 243,930 tons of scrubber sludge would be disposed of onsite each year (based on annual lime usage of 83,750 tons). Based on a standard 30-foot waste pile, Dominion estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 425 acres (an area approximately 4,300 feet square). The SPS site is 840 acres. While only half this waste volume and land use (213 acres) would be attributable to the 20-year license renewal period alternative, the total numbers are pertinent as a cumulative impact.

Dominion believes that, with proper siting and waste management and monitoring practices, waste disposal would not destabilize any resources. There is space within the SPS footprint for this disposal. Because this land is currently forested, it would require converting approximately 200 acres of forest to waste disposal facilities during the 20-year license renewal term. After closure of the waste site and revegetation, the land would be available for other uses. For these reasons, Dominion believes that waste disposal for the coal-fired alternative would have moderate impacts; the impacts would be clearly noticeable, but would not destabilize any important resource, and further mitigation would be unwarranted.

Other Impacts

Construction of the powerblock and coal storage area would impact some land area and associated terrestrial habitat but, because this is a previously disturbed area at an existing industrial site making maximum use of existing facilities, impacts would be minimal. Visual impacts would be consistent with the industrial nature of the site. As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Construction debris from clearing and grubbing could be disposed of onsite and municipal waste disposal capacity is available. Socioeconomic impacts from the construction workforce would be minimal, because worker relocation would not be expected due to the proximity to Newport News (17 miles from SPS) and other metropolitan areas. Cultural resource impacts would be unlikely, due to the previously disturbed nature of the site.

Operations using the existing cooling canal system would minimize impacts to aquatic resources and water quality. The additional stacks (as high as 600 feet), boilers, and barge deliveries would be an incremental addition to the visual impact from existing SPS structures and operations. Socioeconomic impacts could result from the decrease in the operational workforce from approximately 900 employees at SPS to approximately 200 employees needed to operate the coal facility. Dominion believes these impacts would be small to moderate and would be mitigated by the site's proximity to a large metropolitan area.

Dominion believes that the other construction and operational impacts would be small. In some cases, the impacts would not be detectable and, in all cases, they would be minor and would neither destabilize nor noticeably alter any important attribute of the resource involved. Due to the minor nature of these other impacts, mitigation would not be warranted beyond that mentioned.

7.2.2.2 Gas-Fired Generation

NRC evaluated environmental impacts from gas-fired generation alternatives in the GEIS, focusing on combined-cycle plants. Section 7.2.1.1 presents Dominion's reasons for defining the gas-fired generation alternative as a combined-cycle plant on the SPS site. Land-use impacts from gas-fired units would be less than those of the coal-fired alternative at SPS. Reduced land requirements, due to construction on the existing site and a smaller facility footprint, would reduce impacts to other resources as well: ecological, aesthetic, and cultural. A smaller workforce would have minor adverse socioeconomic impacts. Human health concerns associated with air emissions, waste generation, and aquatic biota losses due to cooling water withdrawals and discharges would all be impacts to consider.

The NRC has evaluated the environmental impacts of constructing and operating four 440-MW combined-cycle gas-fired units as an alternative to nuclear power plant license renewal (Ref. 7.2-9). The NRC analysis is for more power than the SPS gas-fired alternatives analysis because Dominion would install only three 508-MW units. Dominion has independently calculated the gas-fired emissions for the standard combined-cycle units introduced in Section 7.2.1.1, but has adopted the rest of the NRC analysis with necessary Virginia- and Dominion-specific modifications noted.

Air Quality

Natural gas is a relatively clean-burning fossil fuel; the gas-fired alternative would release similar types of emissions, but in lesser quantities than the coal-fired alternative. Control technology for gas-fired turbines focuses on nitrogen oxides emissions. Dominion estimates the gas-fired alternative emissions to be as follows:

Sulfur oxides = 134 tons per year

Nitrogen oxides = 506 tons per year

Carbon monoxide = 664 tons per year

Filterable Particulates = 198 tons per year (all particulates are PM_{10})

Table 7-4 presents the equations Dominion used to calculate these emissions.

The Section 7.2.2.1 discussion of regional air quality and Clean Air Act requirements is also applicable to the gas-fired generation alternative. Nitrogen oxides' effects on ozone levels, sulfur dioxide allowances, and nitrogen oxides emission offsets could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, and regulatory requirements are less stringent, the emissions are still substantial. Dominion concludes that emissions from the gas-fired alternative located at SPS would noticeably alter local air quality, but would not destabilize regional resources. Air quality impacts would therefore be moderate, but considerably less than with coal.

Waste Management

Gas-fired generation would result in almost no waste generation and produce minor, if any, impacts. Dominion concludes that gas-fired generation waste management impacts would be small.

Other Impacts

As is true for the coal-fired alternative, constructing the gas-fired alternative on an existing site (such as SPS) would reduce construction-related impacts. NRC estimated in the GEIS that 110 acres would be needed for a plant site; this much previously disturbed acreage is available within the boundaries of SPS, reducing loss of terrestrial habitat. Aesthetic impacts, erosion and sedimentation, fugitive dust, and construction debris impacts would be similar to the coal-fired alternative, but smaller due to the reduced site size. Socioeconomic impacts of construction would be minimal. However, the GEIS estimates a work force of 150 for gas operations. The reduction in work force could result in adverse socioeconomic impacts. Dominion believes these impacts would be moderate and would be mitigated by the site's proximity to large metropolitan areas.

One very costly (about $160 million) controversial (not-in-my-backyard) action with potential ecological impacts is the installation of approximately 160 miles of a buried 24-inch gas line from Danville, Virginia, to SPS. The pipeline would require an additional 3,000 acres (160 miles x 150 foot easement). Dominion would mitigate the political impacts through public hearings and apply best management practices during construction, such as minimizing soil loss and restoring vegetation immediately after the excavation is backfilled. Construction would result in the loss of some less mobile animals (e.g., toads and turtles). Because these animals are common throughout the area, Dominion expects negligible reduction in their population as a result of construction. Dominion does not expect that installation of the pipeline would create a long-term reduction in the local or regional diversity of plants and animals.

Cultural Resources

Gas pipeline construction could require cultural resource preservation measures. Dominion anticipates that these measures would result in no detectable change in cultural resources, and that the effects would be minor and not exert a destabilizing influence on this resource. Dominion concludes that impacts to cultural resources would be small, if any.

7.2.2.3 Purchased Power

As discussed in Section 7.2.1.2, Dominion assumes that the generating technology used under the purchased power alternative would be one of those analyzed by NRC in the GEIS. Dominion is also adopting by reference the NRC analysis of the environmental impacts from those technologies. Under the purchased power alternative, therefore, environmental impacts would still occur, but would be located elsewhere within the region, nation, or Canada.

The purchased power alternative would include adding approximately 100 miles of 500-kV transmission lines to enable Dominion to get out-of-state power from its nearest substation to the SPS load center. This could involve a 100-mile by 300-foot easement (6 square miles) of land-use change with associated terrestrial ecological impacts. Dominion assumes that the environmental impacts of transmission line construction would be approximately equal to those of the Joshua Falls 500-kV interconnect to Ladysmith. Similarly, the environmental impacts of new (offsite) generating capacity would be similar to the environmental impacts of construction and operation of the Remington Combustion Turbine Site, but three sites the size of the Remington site would be required to replace the

SPS power. Loss of the SPS workforce could result in adverse impacts. Dominion believes these impacts would be moderate and would be mitigated by the site's proximity to a large metropolitan area.

TABLES AND FIGURES

Table 7-1
Coal-Fired Alternative

Characteristic	Basis
Unit size = 508 MW ISO rating net[a]	Chosen for comparability to a standard size gas-fired combined-cycle turbine
Unit size = 538 MW ISO rating gross[a]	Calculated based on 6 percent onsite power usage (Dominion experience): 508 MW x 1.06
Number of units = 3	Calculated to be $\leq$ SPS Units 1 and 2 gross capacity of approximately 1,711 MW
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxides emissions (Ref. 7.2-11, Table 1.1-3, pg. 1.1-17).
Fuel type = bituminous, pulverized coal	Typical for coal used in Virginia (Dominion experience)
Fuel heating value = 12,559 Btu/lb	1998 value for coal used in Virginia (Ref. 7.2-12)
Fuel ash content by weight = 10.7 percent	1998 value for coal used in Virginia (Ref. 7.2-12)
Fuel sulfur content by weight = 0.98 percent	1998 value for coal used in Virginia (Ref. 7.2-12)
Uncontrolled NO_x emission = 9.7 lb/ton Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, Pre-NSPS with low-NO_x burner (Ref. 7.2-11, Table 1.1-3 pg. 1.1-17)
Heat rate = 10,200 Btu/KWh	Typical for coal-fired, single cycle steam turbines (Ref. 7.2-13, pg. 106)
Capacity factor = 0.85	Typical for large coal-fired units (Dominion experience)
NO_x control = low NO_x burners, with overfire air and selective catalytic reduction (95 percent reduction)	Best available and widely demonstrated for minimizing NO_X emissions (Dominion experience and Ref. 7.2-11, Table 1.1-2, pg. 1.1-14).
Particulate control = fabric filters or electrostatic precipitators (99.9 percent removal efficiency)	Best available for minimizing particulate emissions (Ref. 7.2-11, pp. 1.1-6 and -7)
SO_x control = Wet scrubber-lime/limestone (95 percent removal efficiency)	Best available for minimizing SO_x emissions (Ref. 7.2-11, Table 1.1-1, pg. 1.1-13)

a. The difference between "net" and "gross" is electricity consumed onsite.

Btu = British thermal unit
CO = carbon monoxide
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt hour
NSPS = New Source Performance Standard
lb = pound
MW = megawatt
NO_X = nitrogen oxides
SO_x = sulfur oxides

Table 7-2
Gas-Fired Alternative

Characteristic	Basis
Unit size = 508 MW ISO rating net:[a] Two 168-MW combustion turbines and a 172-MW heat recovery boiler	Manufacturer's standard size gas-fired combined-cycle plant
Unit size = 528 MW ISO rating gross:[a] Two 174.7 MW combustion turbines and a 179-MW heat recovery boiler (emissions from two combustion turbines only)	Calculated based on 4 percent onsite power usage (Dominion experience): 508 MW × 1.04
Number of units = 3	Calculated to be ≤ SPS Units 1 and 2 gross core capacity of approximately 1,711 MW
Fuel type = natural gas	Assumed
Fuel heating value = 1,059 Btu/ft^3	Dominion standard value for natural gas used in Virginia (Ref. 7.2-12)
Fuel sulfur content = 0.0034 lb/MMBtu	Used when sulfur content is not available (Ref. 7.2-14, Table 3.1-2a, pg. 3.1-11)
NO_x control = low NO_x burner and selective catalytic reduction (SCR)	Typical for large SCR-controlled gas-fired units (Ref. 7.2-14, Section 3.1.4.3, pg. 3.1-7)
Fuel NO_xcontent = 0.0128 lb/MMBtu	Typical for large SCR-controlled gas-fired units (Ref. 7.2-16)
Fuel CO content = 0.0168 lb/MMBtu	Typical for large SCR-controlled gas-fired units (Ref. 7.2-16)
Heat rate = 6,700 Btu/kWh	Dominion experience
Capacity factor = 0.85	Typical for large gas-fired base load units (Dominion experience)

a.The difference between "net" and "gross" is electricity consumed onsite.

Btu = British thermal unit
CO = carbon monoxide
ft^3 = cubic foot
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt hour
MM = million
MW = megawatt
NO_x = nitrogen oxides

Table 7-3
Air Emissions from Coal-Fired Alternative

Parameter	Calculation	Result
Annual coal consumption	$3\ units \times \frac{538\ MW}{unit} \times \frac{10,200\ Btu}{kW \times hr} \times \frac{1,000\ kw}{MW} \times \frac{lb}{12,559\ Btu} \times \frac{ton}{2,000\ lb} \times 0.85 \times \frac{24\ hr}{day} \times \frac{365\ day}{yr}$	4,884,600 tons per year
SO_x[a, c]	$\frac{38 \times 0.98\ lb}{ton} \times \frac{ton}{2,000\ lb} \times (1 - 95/100) \times \frac{4,884,600\ tons}{yr}$	4,548 tons SO_x per year
NO_x[b, c]	$\frac{9.7\ lb}{ton} \times \frac{ton}{2,000\ lb} \times (1 - 95/100) \times \frac{4,884,600\ tons}{yr}$	1,185 tons NO_x per year
CO[b]	$\frac{0.5\ lb}{ton} \times \frac{ton}{2,000\ lb} \times \frac{4,884,600\ tons}{yr}$	1,221 tons CO per year
TSP[d]	$\frac{10 \times 10.7\ lb}{ton} \times \frac{ton}{2,000\ lb} \times (1 - 99.9/100) \times \frac{4,884,600\ tons}{yr}$	261 tons TSP per year
PM_{10}[d]	$\frac{2.3 \times 10.7\ lb}{ton} \times \frac{ton}{2,000\ lb} \times (1 - 99.9/100) \times \frac{4,884,600\ tons}{yr}$	60 tons PM_{10} per year

a. Ref. 7.2-11, Table 1.1-1.
b. Ref. 7.2-11, Table 1.1-2
c. Ref. 7.2-11, Table 1.1-3.
d. Ref. 7.2-11, Table 1.1-4.

CO = carbon monoxide
NO_x = oxides of nitrogen
PM_{10} = particulates having diameter less than 10 microns
SO_x = sulfur oxides
TSP = total suspended particulates

Table 7-4
Air Emissions from Gas-Fired Alternative

Parameter	Calculation	Result
	$3\ units \times \frac{528\ MW}{units} \times \frac{6,700\ Btu}{kW \times hr} \times \frac{1,000\ kW}{MW} \times 0.85 \times \frac{ft^3}{1,059\ Btu} \times \frac{24\ hr}{day} \times \frac{365\ day}{yr}$	74,665,534,912 ft^3 per year
Annual Btu consumption	$\frac{74,665,534,912\ ft^3}{yr} \times \frac{1,059\ Btu}{ft^3} \times \frac{MMBtu}{10^6 Btu}$	79,070,801 MMBtu per year
SO_x[a]	$\frac{0.0034\ lb}{MMBtu} \times \frac{ton}{2,000\ lb} \times \frac{79,070,801\ MMBtu}{yr}$	134 tons SO_x per year
NO_x[b]	$\frac{0.0128\ lb}{MMBtu} \times \frac{ton}{2,000\ lb} \times \frac{79,070,801\ MMBtu}{yr}$	506 tons NO_x per year
CO[b]	$\frac{0.0168\ lb}{MMBtu} \times \frac{ton}{2,000\ lb} \times \frac{79,070,801\ MMBtu}{yr}$	664 tons CO per year
TSP[c]	$\frac{0.005\ lb}{MMBtu} \times \frac{ton}{2,000\ lb} \times \frac{79,070,801\ MMBtu}{yr}$	198 tons filterable TSP per year
PM_{10}[c]	$\frac{198\ tons\ TSP}{yr}$	198 tons filterable PM_{10} per year

a. Ref. 7.2-14, Table 3.1-2a.
b. Ref. 7.2-16, emission factor report for NO_x and CO using natual gas and SCR.
c. Ref. 7.2-17.

CO = carbon monoxide
NO_x = oxides of nitrogen
PM_{10} = particulates having diameter less than 10 microns
SO_2 = sulfur dioxide
TSP = total suspended particulates

Figure 7-1
Utility Generating Capability by Primary Energy Source, 1996
(Ref. 7.2-1, Figure 1)

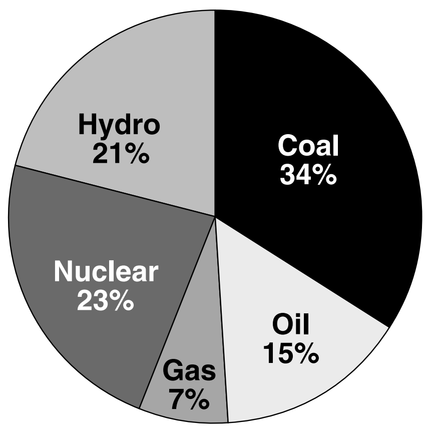


Figure 7-2
Utility Generation Utilization by Primary Energy Source, 1996
(Ref. 7.2-1, Figure 2)

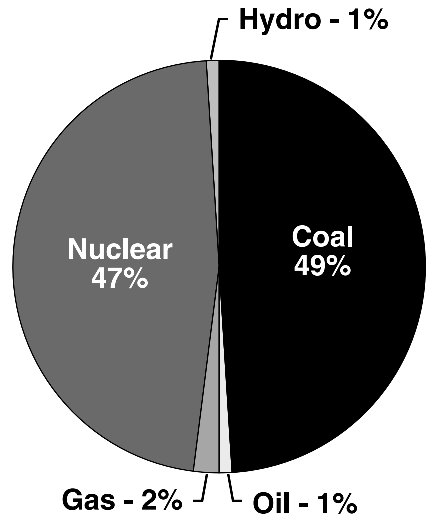
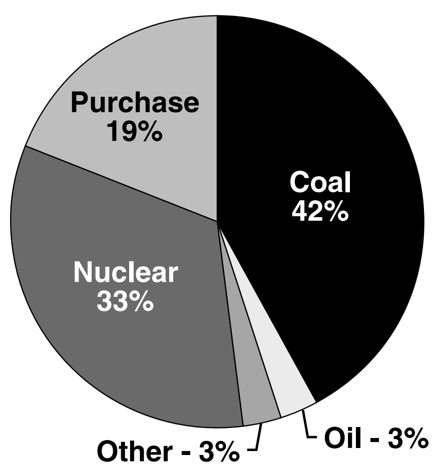


Figure 7-3
Dominion's 1998 Electricity Generating Capability
(Ref. 7.1-1)



7.3 References

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8.0 COMPARISON OF ENVIRONMENTAL IMPACTS OF LICENSE RENEWAL WITH THE ALTERNATIVES

8.1 Discussion

NRC Input

"To the extent practicable, the environmental impacts of the proposal and the alternatives should be presented in comparative form..." 10 CFR 51.45(b)(3) as adopted by 51.53(c)(2)

Chapter 4 analyzes environmental impacts for Surry Power Station Units 1 and 2 (SPS) and Chapter 7 analyzes impacts from renewal alternatives. Table 8-1 summarizes environmental impacts of the proposed action, license renewal, and the feasible alternatives so the reader can compare them. The environmental impacts compared in Table 8-1 are those that are either Category 2 issues for the proposed action (license renewal) or are issues that the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (Ref. 8.1-1) identified as major considerations in an alternatives analysis. For example, although the U.S. Nuclear Regulatory Commission (NRC) concluded that air impacts from the proposed action would be small (Category 1), the GEIS identified major human health concerns associated with air emissions from alternatives (Section 7.2.2.1). Therefore, Table 8-1 compares air impacts among the proposed actions and the alternatives. Table 8-2 is a more detailed comparison of the alternatives.

TABLES

Table 8-1
Impacts Comparison Summary

Impact Area	Proposed Action (License Renewal)	No-Action Alternative			
		Base (Decommissioning)	With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Land Use	SMALL	SMALL	SMALL	MODERATE	MODERATE
Water Quality	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Air Quality	SMALL	SMALL	MODERATE	MODERATE	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	MODERATE	MODERATE	SMALL to MODERATE
Threatened or Endangered Species	SMALL	SMALL	SMALL	SMALL	SMALL
Human Health	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Socioeconomics	SMALL	MODERATE	SMALL to MODERATE	MODERATE	MODERATE
Waste Management	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Aesthetics	SMALL	SMALL	MODERATE	SMALL	SMALL to MODERATE
Cultural Resources	SMALL	SMALL	SMALL	SMALL	SMALL

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource. (10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.)

Table 8-2
Impacts Comparison Detail

Proposed Action (License Renewal)	Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
Description of Action				
SPS license renewals for 20 years each, followed by decommissioning	Decommissioning following expiration of current SPS licenses Adopting by reference, as bounding SPS decommissioning, GEIS description (Section 7.1)	New construction at the SPS site	New construction at the SPS Construct 160 miles of gas pipeline in a 150-foot wide corridor	Construct 100 miles or more of 500-kV transmission lines Could involve construction of new generation capacity out of state Adopting by reference GEIS description of alternate technologies (Section 7.2.1.2)
		Three 508-MWe (net) tangentially-fired dry bottom units; capacity factor 0.85	Three 508-MWe (net) units; each consisting of two 168-MW combustion turbines and a 172-MW heat recovery boiler; capacity factor 0.85	
		Existing intake/ discharge canal system	Existing intake/ discharge canal system	
		Pulverized bituminous coal, 12,559 Btu/pound; 10,200 Btu/kWh; 10.7% ash; 0.98% sulfur; 0.10 lb/MMBtu nitrogen oxides; 4,884,600 tons coal/yr	Natural gas, 1,059 Btu/ft^3; 6,700 Btu/kWh; 0.0006 lb sulfur/MMBtu; 0.0128 lb NO_x/MMBtu; 49,385,078,210 ft^3 gas/yr	
		Low NO_x burners, with overfire air and selective catalytic reduction (95% NO_x reduction efficiency)	Low NO_x burners, selective catalytic reduction	
		Wet scrubber – lime/limestone desulfurization system; flue gas (95% SO_x removal efficiency); 84,000 tons limestone/yr		

Table 8-2 (continued)
Impacts Comparison Detail

Proposed Action (License Renewal)	No-Action Alternative: Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
		Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency) 200 workers (Section 7.2.2.1)	150 workers (Section 7.2.2.2)	
Land Use Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issues 52, 53)	SMALL – Not an impact evaluated by GEIS (Ref. 8.1-1), Section 7.3)	SMALL – 213 acres on existing site for 20 years of ash and scrubber sludge disposal (Section 7.2.2.1)	MODERATE – 110 acres for facility; 3,000 acres for pipeline adjacent to existing previously disturbed easements (Section 7.2.2.2)	MODERATE - 6 square miles for transmission facilities (Section 7.2.2.3) Adopting by reference GEIS description of land use impacts from alternate technologies (Ref. 8.1-1, Section 8.2)
Water Quality Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issues 3, 4, 6, 7-12, 37). Four Category 2 water-use-conflicts and groundwater issues not applicable (Section 4.1, Issue 13; Section 4.6, Issue 34; Section 4.7, Issue 35; and Section 4.8, Issue 39). Small drawdown projected from SPS wells would not affect two local private wells (Section 4.5, Issue 33)	SMALL – Adopting by reference Category 1 issue finding (Table 4-2, Issue 89)	SMALL – Construction impacts minimized by use of best management practices. Operation impacts minimized by use of existing water intake/discharge system (Section 7.2.2.1)	SMALL – Reduced cooling water demands inherent in combined-cycle design and use of closed-cycle cooling minimizes impacts (Section 7.2.2.2)	SMALL to MODERATE - Adopting by reference GEIS description of water quality impacts from alternate technologies (Ref. 8.1-1, Section 8.2)

Table 8-2 (continued)
Impacts Comparison Detail

Proposed Action (License Renewal)	No-Action Alternative: Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
Air Quality Impacts				
SMALL – Adopting by reference Category 1 issue finding (Table 4-2, Issue 51). Category 2 issue not applicable (Section 4.11, Issue 50)	SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issue 88)	MODERATE – • 4,548 tons SO_x/yr • 1,185 tons NO_x/yr • 1,221 tons CO/yr • 261 tons TSP/yr • 60 tons PM_{10}/yr (Section 7.2.2.1)	MODERATE – • 134 tons SO_x/yr • 506 tons NO_x/yr • 664 tons CO/yr • 198 tons PM_{10}/yr[a] (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of air quality impacts from alternate technologies (Ref. 8.1-1, Section 8.2)
Ecological Resource Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issues 15-24, 45-48). One Category 2 issue not applicable (Section 4.9, Issue 40). Dominion holds a current VPDES permit, which constitutes compliance with Clean Water Act Section 316(b) (Section 4.2, Issue 25; Section 4.3, Issue 26). Dominion holds a current VPDES permit with a variance for thermal releases from SPS (Section 4.4, Issue 27)	SMALL – Adopting by reference Category 1 issue finding (Table 4-2, Issue 90)	MODERATE – 213 acres of forested land could be required for ash/sludge disposal over 20 year license renewal term. (Section 7.2.2.1)	MODERATE – Construction of 160 miles of new gas pipeline could alter habitat and result in the loss of some wildlife in 3,000 acres (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of ecological resource impacts from alternate technologies. (Ref. 8.1-1, Section 8.2)
Threatened and Endangered Species Impacts				
SMALL – Continued operations would not adversely affect any threatened or endangered species (Section 4.10, Issue 49)	SMALL – Not an impact evaluated by GEIS (Ref. 8.1-1, Section 7.3)	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats

Table 8-2 (continued)
Impacts Comparison Detail

Proposed Action (License Renewal)	No-Action Alternative			
	Base (Decommissioning)	With Coal-Fired Generation	With Gas-Fired Generation	With Purchased Power
Human Health Impacts				
SMALL – Category 1 issues (Table 4-2, Issues 56, 58, 61, 62). Risk from microbiological organisms minimal due to low discharge temperatures (Section 4.12, Issue 57). Risk due to transmission-line induced currents minimal due to conformance with consensus code (Section 4.13, Issue 59)	SMALL – Adopting by reference Category 1 issue finding (Table 4-2, Issue 86)	MODERATE – Adopting by reference GEIS conclusion that risks such as cancer and emphysema from emissions are likely (Ref. 8.1-1, Section 8.3.9)	SMALL – Adopting by reference GEIS conclusion that some risk of cancer and emphysema exists from emissions (Ref. 8.1-1, Table 8.2)	SMALL to MODERATE – Adopting by reference GEIS description of human health impacts from alternate technologies (Ref. 8.1-1, Section 8.2)
Socioeconomic Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issues 64, 67). Two Category 2 issues not applicable (Section 4.16, Issue 66 and Section 4.17.1, Issue 68). Proximity to large, metropolitan area minimizes potential for housing impacts. (Section 4.14, Issue 63). Plant contribution is 76 percent of county property tax base (Section 4.17.2, Issue 69). Capacity of public water supply and transportation services minimizes potential for related impacts (Section 4.15, Issue 65 and Section 4.18, Issue 70)	MODERATE – Loss of 76% of county property tax could adversely affect public services in the county.	SMALL to MODERATE – Reduction in permanent work force could adversely affect surrounding counties (Section 7.2.2.1)	MODERATE – Reduction in permanent work force could adversely affect surrounding counties (Section 7.2.2.2)	MODERATE – Reduction in permanent work force could adversely affect surrounding counties (Section 7.2.2.3)

Table 8-2 (continued)
Impacts Comparison Detail

Proposed Action (License Renewal)	No-Action Alternative: Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
Waste Management Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issues 77-85)	SMALL – Adopting by reference Category 1 issue finding (Table 4-2, Issue 87	MODERATE – Annually generate 522,000 tons of coal ash and 244,000 tons of scrubber sludge, requiring 213 acres over 20-year license renewal term. Industrial waste generated annually (Section 7.2.2.1)	SMALL – Almost no waste generation (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of waste management impacts from alternate technologies (Ref. 8.1-1, Section 8.2)
Aesthetic Impacts				
SMALL – Adopting by reference Category 1 issue findings (Table 4-2, Issues 73, 74)	SMALL – Not an impact evaluated by GEIS (Ref. 8.1-1, Section 7.3)	MODERATE – Tall stacks would be visible from Hog Island Wildlife Management Area and from the James River. Depending on season and weather, stacks could be visible from Chippokes State Park (2 miles distant), Historic Jamestown (3 miles distant), the Colonial Parkway (3 miles distant) and the Jamestown Ferry (5 miles distant) (Section 7.2.2.1)	SMALL– Steam turbines and stacks (approximately 200 feet tall) would create visual impacts comparable to those from existing SPS facilities (Section 7.2.2.2)	SMALL to MODERATE – Adopting by reference GEIS description of aesthetic impacts from alternate technologies (Ref. 8.1-1, Section 8.2)

Table 8-2 (continued)
Impacts Comparison Detail

Proposed Action (License Renewal)	No-Action Alternative: Base (Decommissioning)	No-Action Alternative: With Coal-Fired Generation	No-Action Alternative: With Gas-Fired Generation	No-Action Alternative: With Purchased Power
Cultural Resource Impacts				
SMALL – Lack of resources and SHPO consultation minimizes potential for impact (Section 4.19, Issue 71)	SMALL – Not an impact evaluated by GEIS (Ref. 8.1-1, Section 7.3)	SMALL – Impacts unlikely due to lack of resources onsite (Section 7.2.2.1)	SMALL – One hundred sixty miles of pipeline construction in eastern Virginia could impact some cultural resources (Section 7.2.2.3)	SMALL – Adopting by reference GEIS description of cultural resource impacts from alternate technologies (Ref. 8.1-1, Section 8.2)

a. All TSP for gas-fired alternative is PM_{10}

Btu	=	British thermal unit	MW	=	megawatt
ft^3	=	cubic foot	NO_X	=	nitrogen oxides
gal	=	gallon	PM_{10}	=	particulates having diameter less than 10 microns
GEIS	=	Generic Environmental Impact Statement (Ref. 8.1-1)	SHPO	=	State Historic Preservation Officer
kWh	=	kilowatt hour	SO_x	=	sulfur dioxides
lb	=	pound	TSP	=	total suspended particulates
MM	=	million	yr	=	year

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize any important attribute of the resource. (10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3).

8.2 References

Ref. 8.1-1 U.S. Nuclear Regulatory Commission. 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS). Volumes 1 and 2. NUREG-1437. Washington, DC.

9.0 STATUS OF COMPLIANCE

9.1 Proposed Action

NRC Input

"The environmental report shall list all Federal permits, licenses, approvals and other entitlements which must be obtained in connection with the proposed action and shall describe the status of compliance with these requirements. The environmental report shall also include a discussion of the status of compliance with applicable environmental quality standards and requirements including, but not limited to, applicable zoning and land-use regulations, and thermal and other water pollution limitations or requirements which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection." 10 CFR 51.45(d), as required by 10 CFR 51.53(c)(2)

9.1.1 General

Table 9-1 lists environmental authorizations that Dominion has obtained for current Surry Power Station (SPS) operations. In this context, Dominion uses "authorizations" to include permits, licenses, approvals, and other entitlements. Dominion expects to continue renewing these authorizations during the current license period and through the U.S. Nuclear Regulatory Commission (NRC) license renewal period. Based on the new and significant information identification process described in Chapter 5, Dominion concludes that SPS is in compliance with applicable environmental standards and requirements.

Table 9-2 lists additional environmental authorizations and consultations that would be conditions precedent to NRC renewal of the SPS licenses to operate. As indicated, Dominion anticipates needing relatively few such authorizations and consultations. Sections 9.1.2 through 9.1.5 discuss some of these items in more detail.

9.1.2 Threatened or Endangered Species

Section 7 of the Endangered Species Act (16 USC 1531 et seq.) requires federal agencies to ensure that agency action is not likely to jeopardize any species that is listed or proposed for listing as endangered or threatened. Depending on the action involved, the Act requires consultation with the U.S. Fish and Wildlife Service (FWS) regarding effects on non-marine species, the National Marine Fisheries Service (NMFS) for marine species, or both. FWS and NMFS have issued joint procedural regulations at 50 CFR 402, Subpart B, that address consultation, and FWS maintains the joint list of threatened and endangered species at 50 CFR 17.

As discussed in Section 4.10, threatened and endangered species might be present in the vicinity of SPS. Although not required of an applicant by federal law or by NRC regulation, Dominion has chosen to invite comment from federal and state agencies regarding potential effects that SPS license renewal might have. Appendix C includes copies of correspondence between Dominion and FWS and NMFS. In addition, Dominion has corresponded with the Virginia Department of Game & Inland Fisheries regarding potential effects on Commonwealth-listed species; Appendix C also includes copies of this correspondence.

The National Marine Fisheries Service has determined that "no federally listed or proposed threathened or endangered species and/or designated critical habitat for listed species under the jurisdiction of the National Marine Fisheries Service are known to exist in the project area" (letter, Colligan to Banks, March 23, 2001; in Appendix C). Therefore, no further Section 7 Endangered Species Act consultation is required with this agency.

9.1.3 Coastal Zone Management

The Federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on applicants for a federal license to conduct an activity if that activity could affect a state's coastal zone. The Act requires the applicant to certify to the licensing agency that the proposed activity would be consistent with the state's federally-approved coastal zone management plan (16 USC 1456[c][3][A]). The National Oceanic and Atmospheric Administration has promulgated implementing regulations that indicate that the requirement is applicable to renewal of federal licenses for activities not previously reviewed by the state [15 CFR 930.51(b)(1)]. The regulation requires that the license applicant provide its certification to the federal licensing agency and a copy to the applicable state agency [15 CFR 930.57(a)].

The NRC Office of Nuclear Reactor Regulation has issued guidance to its staff regarding compliance with the Act (Ref. 9.1-1, Attachment 5). This guidance acknowledges that Virginia has an approved coastal zone management program. SPS, located in Surry County, is within the Virginia coastal zone (Tidewater Virginia) (Ref. 9.1-2). Dominion submitted project-descriptive material and a draft certification to the Virginia Department of Environmental Quality. Concurrent with submitting the *Applicant's Environmental Report - Operating License Renewal Stage* to NRC, Dominion will submit a copy to the Commonwealth in fulfillment of the regulatory requirement for submitting a copy of the coastal zone consistency certification to the state.

9.1.4 Historic Preservation

Section 106 of the National Historic Preservation Act (16 USC 470 et seq.) requires federal agencies having the authority to license any undertaking, prior to issuing the license, to take into account the effect of the undertaking on historic properties and to afford the Advisory

Council on Historic Preservation an opportunity to comment on the undertaking. Council regulations provide for establishing an agreement with any State Historic Preservation Officer (SHPO) to substitute state review for Council review (35 CFR 800.7). Although not required of an applicant by federal law or NRC regulation, Dominion has chosen to invite comment by the Virginia SHPO. Dominion initiated correspondance with the SHPO by letter dated April 12, 2000, and is awaiting the agency's response. Appendix D includes a copy of Dominion correspondence with the SHPO, regarding potential effects that SPS license renewal might have on historic or cultural resources.

9.1.5 Water Quality (401) Certification

Federal Clean Water Act (CWA) Section 401 requires that applicants for a federal license to conduct an activity that might result in a discharge into navigable waters provide the licensing agency with a certification from the state that the discharge will comply with applicable CWA requirements (33 USC 1341). Dominion is applying to NRC for a license (i.e., license renewal) to continue SPS operations. These operations result in discharges to the James River, a navigable waterway within the Commonwealth of Virginia.

The Commonwealth of Virginia has U.S. Environmental Protection Agency authorization to implement the National Pollutant Discharge Elimination System within the state for facilities such as SPS. It is Dominion's understanding that Commonwealth issuance of a VPDES permit constitutes Section 401 certification by the Commonwealth for the permitted activity. Appendix B contains a copy of the SPS VPDES permit cover sheet and excerpts. Dominion concludes that providing this permit to NRC satisfies the CWA Section 401 requirement to provide certification by the state.

9.2 Alternatives

NRC Input

"The discussion of alternatives in the report shall include a discussion of whether the alternatives will comply with such applicable environmental quality standards and requirements." 10 CFR 51.45(d), as required by 10 CFR 51.53(c)(2)

The coal, gas, and purchased-power alternatives discussed in Section 7.2.1 probably could be constructed and operated so as to comply with all applicable environmental quality standards and requirements. Dominion notes, however, that increasingly stringent air quality protection requirements could make construction of a large new fossil-fuel-fired power plant not cost justified for base-load generation in many locations, when compared to the proposed action, license renewal.

TABLES

Table 9-1
Environmental Authorizations for Current SPS Operations

Agency	Authority	Requirement	Number	Issue Date or Expiration Date	Activity Covered
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.)	License to operate	DPR-32 (Unit 1); DPR-37 (Unit 2)	Expires on 05/25/12 (Unit 1); 01/29/13 (Unit 2)	Operation of Units 1 and 2
U.S. Fish and Wildlife Service	Migratory Bird Treaty Act (16 USC 703 – 712)	Permit	MB705136-0	Issued 01/01/01; Expires 12/31/00	Removal of up to 15 osprey nests causing safety hazards
U.S. Army Corps of Engineers	Federal Clean Water Act, Section 404 (33 USC 1344)	Authorization to use regional permit	97-RP-19, Project 99-V1336	Issued 08/27/99; Expires 08/12/03	Periodic maintenance dredging of the intake channel in the James River
U.S. Department of Transportation	49 CFR 107, Subpart G	Registration	053100002 0241	Issued 06/05/00 Expires 06/30/01	Hazardous materials shipments
VMRC	Cov Title 28.2, Chapters 12 and 13	Permit	VMRC 92-1347	Issued 08/02/99; Expires 12/31/02	Maintenance dredging of the intake channel in the James River

Table 9-1 (continued)
Environmental Authorizations for Current SPS Operations

Agency	Authority	Requirement	Number	Issue Date or Expiration Date	Activity Covered
VDEQ	9 VAC 25-610-40	Permit	GW0003900	Issued 08/01/99; Expires 08/01/09	Withdrawal of groundwater from wells for use as potable, process, and cooling water for SPS and Gravel Neck Combustion Turbines Station
Virginia Department of Health, Bureau of Water Supply Engineering	Section 3.14, Waterworks Regulations of the Virginia Department of Health	Permit	3181800	Issued 03/07/78; no expiration	Authorizes operation of a non-community waterworks
VDEQ	Federal Clean Water Act, Section 402 (33 USC 1342); Virginia State Water Control Law	Permit	VA0004090	Issued 09/23/96; Expires 09/23/01	Plant and stormwater discharges

Table 9-1 (continued)
Environmental Authorizations for Current SPS Operations

Agency	Authority	Requirement	Number	Issue Date or Expiration Date	Activity Covered
VDEQ	9 VAC 5-80-10	Permit	Letter, Williams (VDEQ) to Ahladas (VP), 09/27/93	Issued 09/27/93; No expiration date	Installation and operation of the emergency blackout generator
VDEQ	9 VAC 5-20-160	Registration	50336	Annual re-certification	Air emission sources
VDEQ	Federal Clean Air Act, Title V (42 USC 7661 et seq.); 9 VAC 5-80-10	Permit	None	Application submitted 01/12/98; Revised 04/07/98	Air emission source operation

Source: Modified from Ref. 9.1-1.
COV – Code of Virginia
NRC – U.S. Nuclear Regulatory Commission
USC – United States Code
VAC – Virginia Administrative Code
VDEQ – Virginia Department of Environmental Quality
VMRC – Virginia Marine Resources Commission
VP – Virginia Power

TABLE 9-2
Environmental Authorizations for SPS License Renewal[a]

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License renewal	Environmental Report submitted in support of license renewal application.
FWS and NMFS	Endangered Species Act, Section 7 (16 USC 1536)	Consultation	Requires federal agency issuing a license to consult with FWS and NMFS. (Appendix C)
Virginia Department of Environmental Quality	Clean Water Act, Section 401 (33 USC 1341)	Certification	SPS VPDES permit constitutes State Certification. (Appendix B)
Virginia Department of Historic Resources	National Historic Preservation Act, Section 106 (16 USC 470f)	Consultation	Requires Federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Officer. (Appendix D)

TABLE 9-2 (continued)
Environmental Authorizations for SPS License Renewal[a]

Agency	Authority	Requirement	Remarks
Virginia Department of Environmental Quality	Federal Coastal Zone Management Act (16 USC 1451 et seq.)	Certification	Requires an applicant to provide certification to the federal agency issuing the license that license renewal would be consistent with the federally-approved state coastal zone management program. Based on its review of the proposed activity, the state must concur with or object to the applicant's certification. (Appendix E)

a. No renewal-related requirements identified for local or other agencies.
FWS = U.S. Fish and Wildlife Service
NMFS = National Marine Fisheries Service
SPS = Surry Power Station
VPDES = Virginia Pollutant Discharge Elimination System

9.3 References

Ref. 9.1-1 U.S. Nuclear Regulatory Commission. 1999. *Revision 2, Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues*. Office of Nuclear Reactor Regulation.

Ref. 9.1-2 Virginia Administrative Code, Title 10.1 – Conservation Q Subtitle 10.1-100 Activities Administered by the Department of Conservation and Recreation, Chapter 1, Administration. Available at http://leg1.state.va.us/cgi-bin/legp504.exe?000+code+10.1-2101. Accessed June 2000.

APPENDIX A
NRC NEPA ISSUES FOR LICENSE RENEWAL OF NUCLEAR POWER PLANTS

Dominion prepared this environmental report in accordance with the requirements of U.S. Nuclear Regulatory Commission (NRC) regulation 10 CFR 51.53. NRC included in the regulation a list of National Environmental Policy Act (NEPA) issues associated with license renewal of nuclear power plants. Table A-1 lists these 92 issues and identifies the section in which Dominion addressed each issue in the environmental report. For expediency, Dominion assigned a number to each issue and uses the issue numbers throughout the environmental report.

Table A-1
Surry Power Station Environmental Report
Discussion of License Renewal NEPA Issues[a]

Issue	Category	Section of this Environmental Report
1. Impacts of refurbishment on surface water quality	1	4.0
2. Impacts of refurbishment on surface water use	1	4.0
3. Altered current patterns at intake and discharge structures	1	4.0
4. Altered salinity gradients	1	4.0
5. Altered thermal stratification of lakes	1	4.0
6. Temperature effects on sediment transport capacity	1	4.0
7. Scouring caused by discharged cooling water	1	4.0
8. Eutrophication	1	4.0
9. Discharge of chlorine or other biocides	1	4.0
10. Discharge of sanitary wastes and minor chemical spills	1	4.0
11. Discharge of other metals in waste water	1	4.0
12. Water use conflicts (plants with once-through cooling systems)	1	4.0
13. Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	4.1
14. Refurbishment impacts to aquatic resources	1	4.0
15. Accumulation of contaminants in sediments or biota	1	4.0
16. Entrainment of phytoplankton and zooplankton	1	4.0
17. Cold shock	1	4.0

Table A-1 (continued)
Surry Power Station Environmental Report
Discussion of License Renewal NEPA Issues[a]

Issue	Category	Section of this Environmental Report
18. Thermal plume barrier to migrating fish	1	4.0
19. Distribution of aquatic organisms	1	4.0
20. Premature emergence of aquatic insects	1	4.0
21. Gas supersaturation (gas bubble disease)	1	4.0
22. Low dissolved oxygen in the discharge	1	4.0
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	4.0
24. Stimulation of nuisance organisms (e.g., shipworms)	1	4.0
25. Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	4.2
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	4.3
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	4.4
28. Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	4.0
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	4.0
30. Heat shock for plants with cooling-tower-based heat dissipation systems	1	4.0

**Table A-1 (continued)
Surry Power Station Environmental Report
Discussion of License Renewal NEPA Issues[a]**

Issue	Category	Section of this Environmental Report
31. Impacts of refurbishment on groundwater use and quality	1	4.0
32. Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	1	4.0
33. Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	4.5
34. Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	4.6
35. Groundwater use conflicts (Ranney wells)	2	4.7
36. Groundwater quality degradation (Ranney wells)	1	4.0
37. Groundwater quality degradation (saltwater intrusion)	1	4.0
38. Groundwater quality degradation (cooling ponds in salt marshes)	1	4.0
39. Groundwater quality degradation (cooling ponds at inland sites)	2	4.8
40. Refurbishment impacts to terrestrial resources	2	4.9
41. Cooling tower impacts on crops and ornamental vegetation	1	4.0
42. Cooling tower impacts on native plants	1	4.0
43. Bird collisions with cooling towers	1	4.0
44. Cooling pond impacts on terrestrial resources	1	4.0
45. Power line right-of-way management (cutting and herbicide application)	1	4.0
46. Bird collisions with power lines	1	4.0

Table A-1 (continued)
Surry Power Station Environmental Report
Discussion of License Renewal NEPA Issues[a]

Issue	Category	Section of this Environmental Report
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4.0
48. Floodplains and wetlands on power line right-of-way	1	4.0
49. Threatened or endangered species	2	4.10
50. Air quality during refurbishment (non-attainment and maintenance areas)	2	4.11
51. Air quality effects of transmission lines	1	4.0
52. Onsite land use	1	4.0
53. Power line right-of-way land use impacts	1	4.0
54. Radiation exposures to the public during refurbishment	1	4.0
55. Occupational radiation exposures during refurbishment	1	4.0
56. Microbiological organisms (occupational health)	1	4.0
57. Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	4.12
58. Noise	1	4.0
59. Electromagnetic fields, acute effects (electric shock)	2	4.13
60. Electromagnetic fields, chronic effects	NA[b]	4.0
61. Radiation exposures to public (license renewal term)	1	4.0
62. Occupational radiation exposures (license renewal term)	1	4.0

Table A-1 (continued)
Surry Power Station Environmental Report
Discussion of License Renewal NEPA Issues[a]

Issue	Category	Section of this Environmental Report
63. Housing impacts	2	4.14
64. Public services: public safety, social services, and tourism and recreation	1	4.0
65. Public services: public utilities	2	4.15
66. Public services: education (refurbishment)	2	4.16
67. Public services: education (license renewal term)	1	4.0
68. Offsite land use (refurbishment)	2	4.17.1
69. Offsite land use (license renewal term)	2	4.17.2
70. Public services: transportation	2	4.18
71. Historic and archaeological resources	2	4.19
72. Aesthetic impacts (refurbishment)	1	4.0
73. Aesthetic impacts (license renewal term)	1	4.0
74. Aesthetic impacts of transmission lines (license renewal term)	1	4.0
75. Design basis accidents	1	4.0
76. Severe accidents	2	4.20
77. Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	1	4.0
78. Offsite radiological impacts (collective effects)	1	4.0
79. Offsite radiological impacts (spent fuel and high-level waste disposal)	1	4.0
80. Nonradiological impacts of the uranium fuel cycle	1	4.0
81. Low-level waste storage and disposal	1	4.0
82. Mixed waste storage and disposal	1	4.0

Table A-1 (continued)
Surry Power Station Environmental Report
Discussion of License Renewal NEPA Issues[a]

Issue	Category	Section of this Environmental Report
83. Onsite spent fuel	1	4.0
84. Nonradiological waste	1	4.0
85. Transportation	1	4.0
86. Radiation doses (decommissioning)	1	4.0
87. Waste management (decommissioning)	1	4.0
88. Air quality (decommissioning)	1	4.0
89. Water quality (decommissioning)	1	4.0
90. Ecological resources (decommissioning)	1	4.0
91. Socioeconomic impacts (decommissioning)	1	4.0
92. Environmental justice	NA[b]	2.11

a. Source: 10 CFR 51, Subpart A, Appendix A, Table B-1. (Issue numbers added to facilitate discussion.)
b. Not applicable. Regulation does not categorize this issue.
NEPA = National Environmental Policy Act.

APPENDIX B
VPDES PERMIT

The Virginia Pollutant Discharge Elimination System permit for Surry Power Station is approximately 80 pages long. Appendix B contains a copy of the permit cover page to enable confirmation of the permit's existence and one other page that pertains to one issue.

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

Permit No. VA0004090

Effective Date: September 23, 1996
Expiration Date: September 23, 2001

AUTHORIZATION TO DISCHARGE UNDER THE VIRGINIA POLLUTANT DISCHARGE ELIMINATION SYSTEM AND THE VIRGINIA STATE WATER CONTROL LAW

In compliance with the provisions of the Clean Water Act as amended and pursuant to the State Water Control Law and regulations adopted pursuant thereto, the following owner is authorized to discharge in accordance with the effluent limitations, monitoring requirements, and other conditions set forth in this permit.

Owner:	Virginia Electric & Power Co.
Facility Name:	Virginia Electric & Power Co.-Surry Power Station
City:	N/A
County:	Surry
Facility Location:	State Rt. 650 in Surry County

The owner is authorized to discharge to the following receiving stream:

Stream:	James River
River Basin:	James River (Lower)
River Subbasin:	N/A
Section:	1
Class:	II
Special Standards:	a

The authorized discharge shall be in accordance with this cover page, Part I - Effluent Limitations and Monitoring Requirements, Part II - Monitoring and Reporting Requirements, and Part III - Management Requirements, as set forth herein.

Director, Department of Environmental Quality

9/23/96
Date

C. Other Requirements or Special Conditions - continued:

9. The permittee shall sample the first discharge from Package Boilers A & B (Outfall 107) after the effective date of the permit and complete Form 2C, Table V, Part A and any parameters believed present in Parts B and C for Outfall 107. Data shall be submitted to the Piedmont Regional Office within two months of the sample date.

10. Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the Department of Environmental Quality that the units in a particular location cannot operate at or below this level of chlorination.

11. All limitations and monitoring requirements for radioactivity in the wastewater shall be regulated by the Nuclear Regulatory Commission.

12. Within **90 days** of the effective date of this permit, the permittee shall submit to the DEQ Piedmont Regional Office a groundwater monitoring program. The purpose of that program will be to determine if the activities at the Gravel Neck Facility are resulting in violations of the State Water Control Board's Groundwater Standards. The program may be approved by the Director of the DEQ Regional Office. Once approved, the program shall become an enforceable condition of this permit.

13. There shall be no discharge of tank bottom waters at the Gravel Neck Facility.

14. Should effluent monitoring indicate the need for any water quality-based limitations, this permit may be modified or alternatively revoked and reissued to incorporate appropriate limitations.

15. This permit shall be modified or alternatively revoked and reissued to include new or alternative nutrient limitations should the Board adopt nutrient standards for the Chesapeake Bay and tributary river basin, or if a future water quality regulation, statute, or water quality management plan requires new or alternative nutrient control.

16. The permittee has requested alternative effluent limitations under 316(a). Pursuant to a Study Plan approved by the Board, Virginia Power conducted a 316(a) study and submitted a 316(a) Demonstration Report on September 1, 1977. The Board has reviewed the study and demonstration and found that effluent limitations more stringent than the thermal limitations included in this permit are not necessary to assure the protection and propagation of a balanced indigenous community of shellfish, fish and wildlife in the James River.

17. All pump and haul activities involving the removal of tank bottom waters from the bulk storage tanks shall require that a report detailing the following be prepared and submitted to the Department of Environmental Quality by the 10th of the month following the operation:

    a) The name of the contractor responsible for hauling the waste.
    b) The date and time the contractor hauled the waste.
    c) The final destination and disposition of the waste.
    d) The disposal quantity of waste.

18. Toxics Management Plan

    a. Biological Monitoring:

APPENDIX C
SPECIAL-STATUS SPECIES CORRESPONDENCE

Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, Virginia 23060

April 12, 2000

VIRGINIA POWER

Ms. Karen Mayne, Supervisor
Virginia Field Office
US Fish & Wildlife Service
6669 Short Lane
Gloucester, VA 23061

Re: Surry and North Anna Power Stations Nuclear License Renewal and Environmental Reports

Dear Ms. Mayne:

Virginia Power is preparing applications for renewing the operating licenses for its Surry and North Anna Power Stations. We intend the applications to be consistent with US Fish & Wildlife Service's requirements and with the priorities of our communities. As part of the license renewal process, the Nuclear Regulatory Commission (NRC) requires that applicants identify adverse impacts to threatened and endangered species resulting from continued operation of the facility or from refurbishment activities associated with license renewal. The operation of Surry and North Anna Power Stations has had no adverse impact on any threatened or endangered species. In addition, no future operational or refurbishment activities are planned which would invalidate this conclusion.

As a matter of course, the NRC will request an informal consultation with your agency regarding our actions. The time frame for the NRC consultation request is anticipated to be in the second half of 2001, following a September applications submittal. To assist you in responding to this request, I have enclosed figures for each station site depicting local and regional vicinities.

It is our expectation that, by contacting you early in the application process, we can identify any questions needing to be addressed or data needed to facilitate a smooth and expeditious NRC consultation. We will appreciate your notifying us of your comments and of any information or actions required of Virginia Power in advance to assist in meeting shared objectives.

Please contact Mr. Tony Banks at (804) 273-2170 should you or your staff have any questions or comments.

Respectfully,

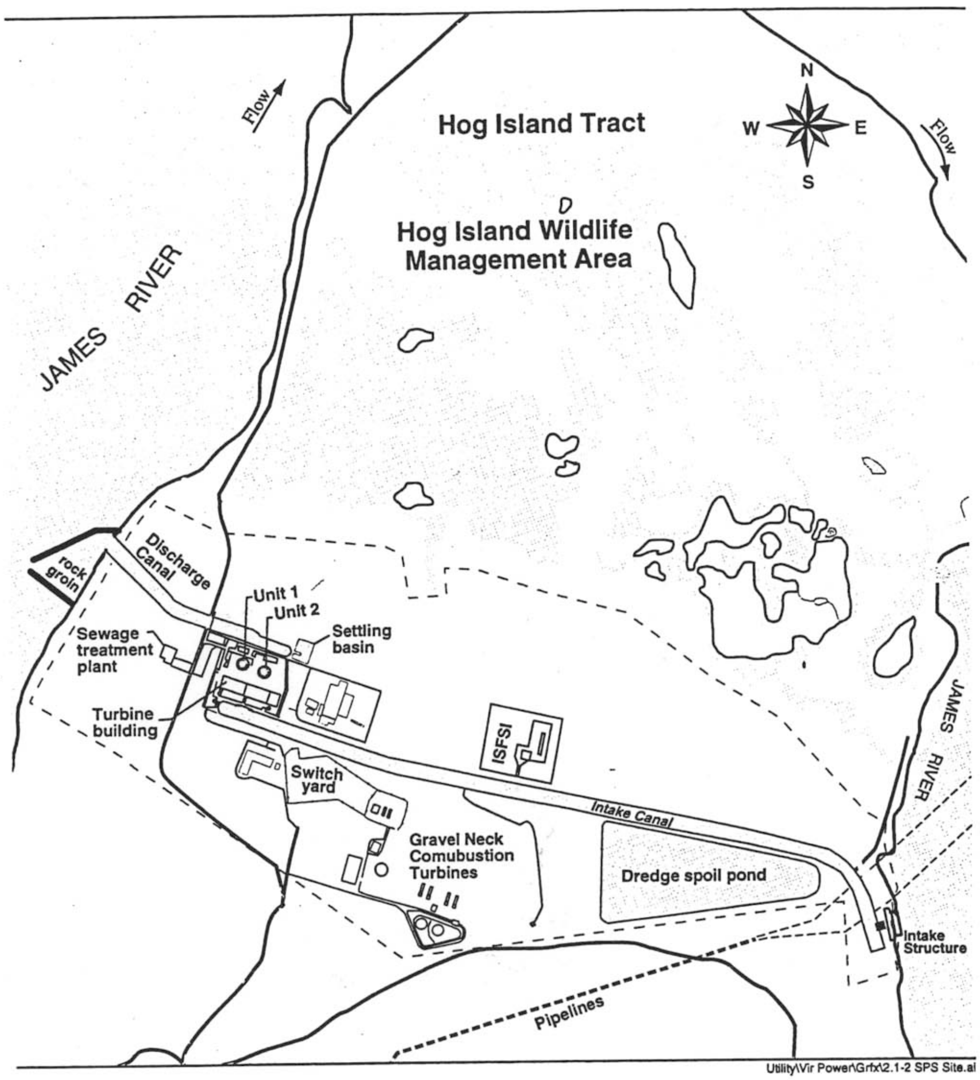
P. F. Faggert

P. F. Faggert, Vice-President and
Chief Environmental Officer

Enclosure: Figures of Surry and North Anna vicinities

cc:

4-00ERconsult1.ltr

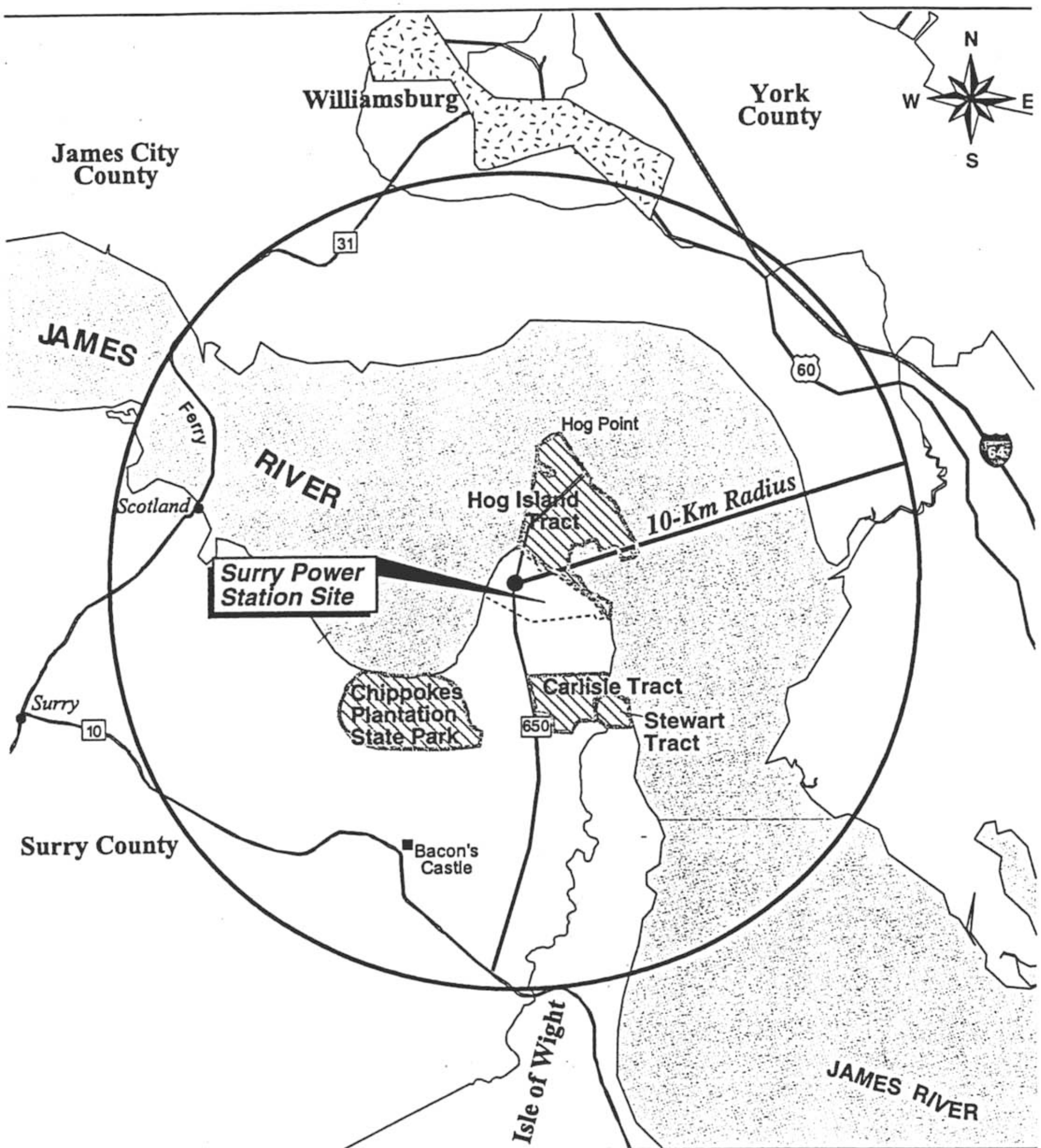


LEGEND

ISFSI Independent Spent Fuel Storage Installation

– – – Property line

FIGURE 2.1-2
Virginia Power - SPS Site
LICENSE RENEWAL APPLICATION
Surry Power Station

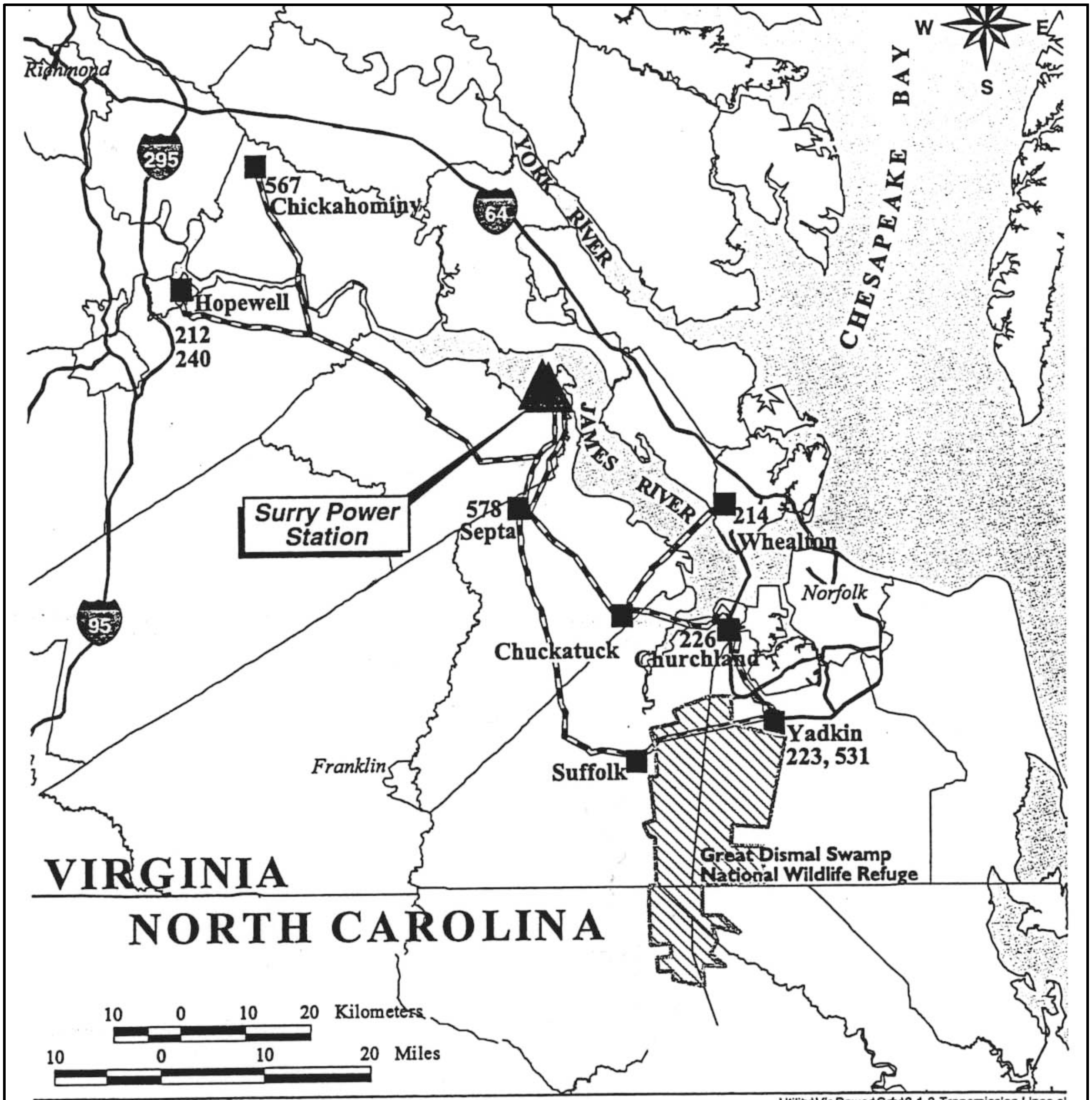


LEGEND

State Property

Urban Areas

FIGURE 2.1-3
Virginia Power - 10 Km SPS Vicinity
LICENSE RENEWAL APPLICATION
Surry Power Station



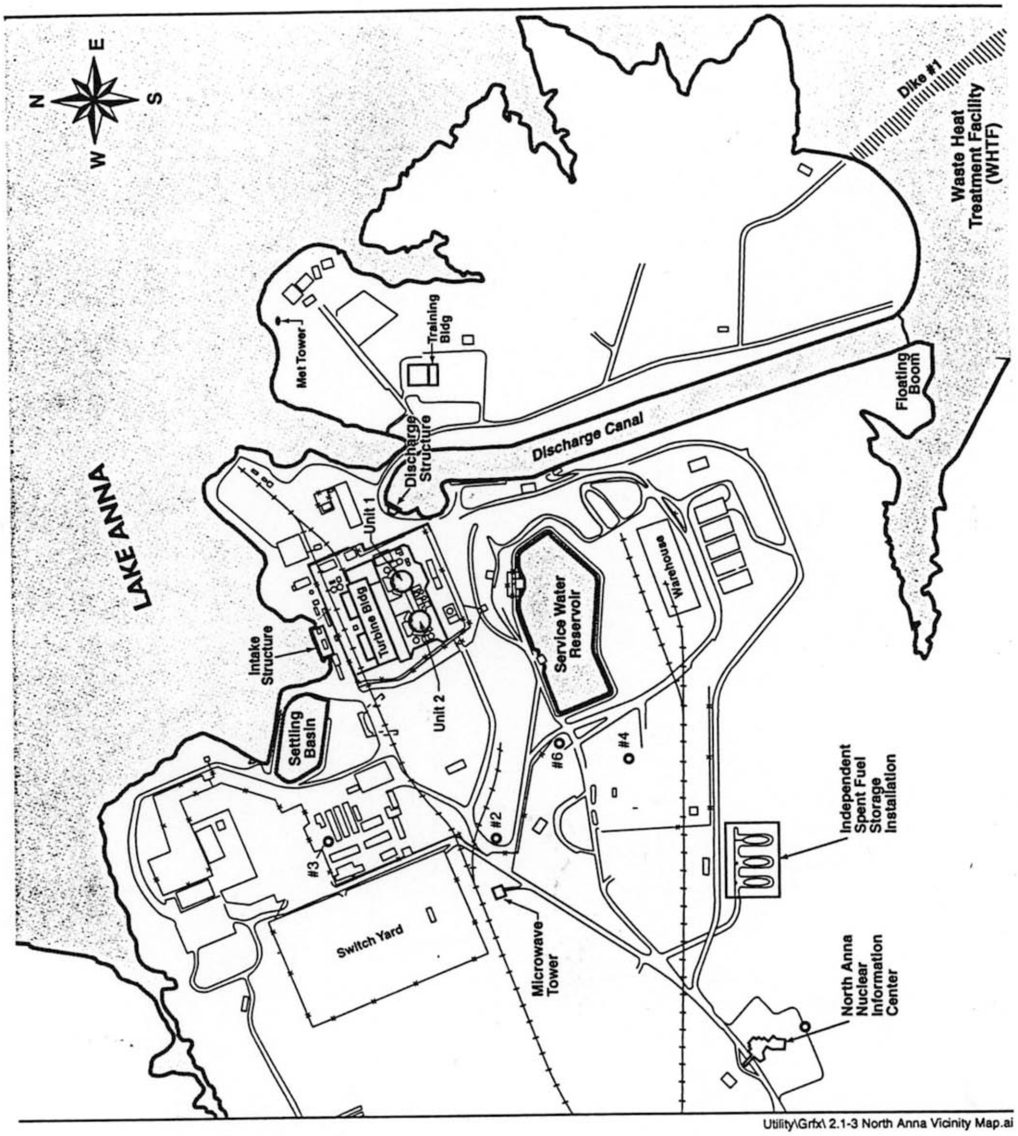
LEGEND

■ Substations

Transmission Lines

290 Line numbers noted at terminus

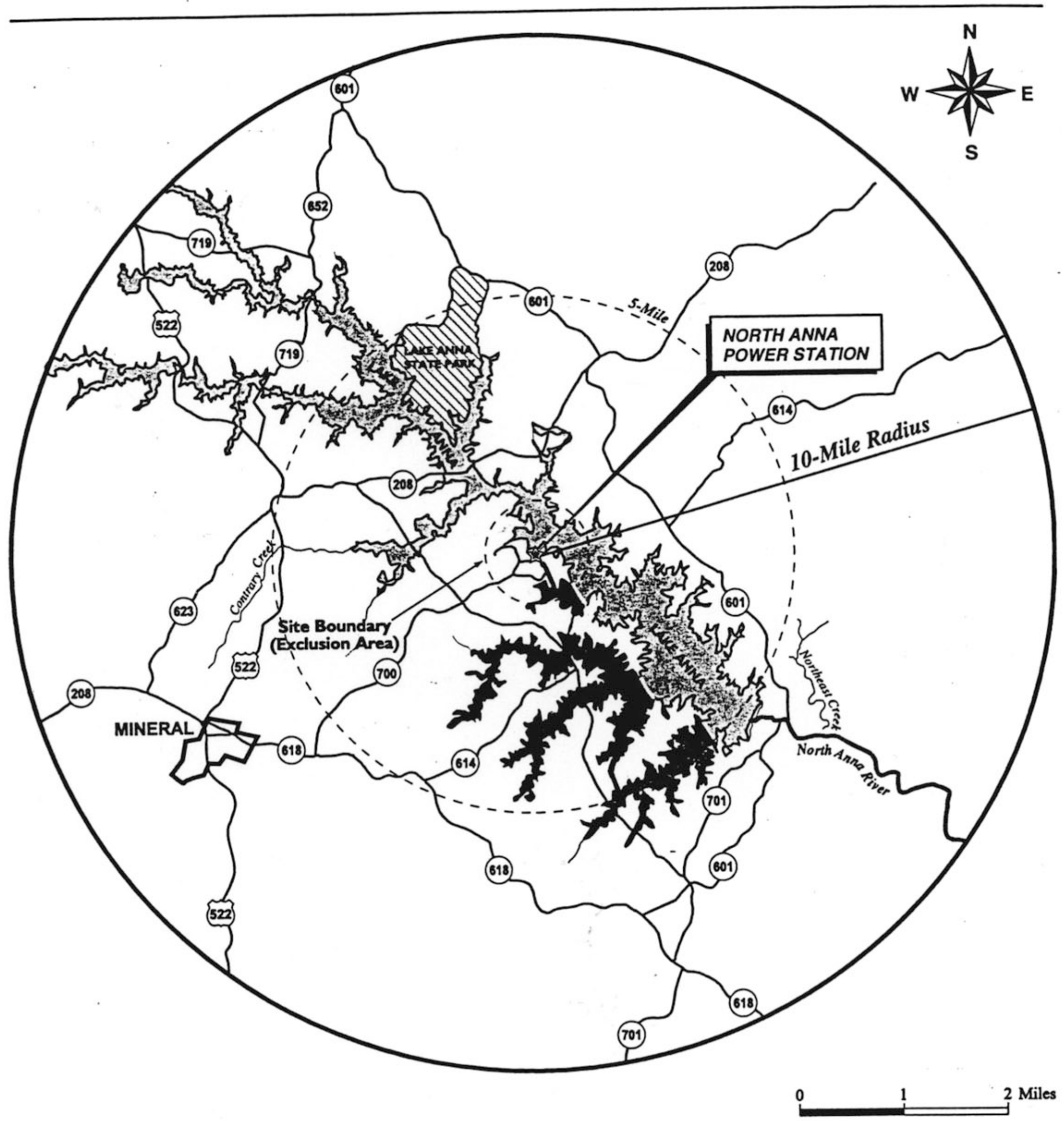
FIGURE 3.1-3
Virginia Power - Transmission Lines
LICENSE RENEWAL APPLICATION
Surry Power Station



LEGEND

- o Groundwater well locations
- Railraod
- Fence

FIGURE 2.1-3
Virginia Power - North Anna Vicinity Map
LICENSE RENEWAL APPLICATION
North Anna Power Station



Utility\Vir Power\Grfx\2.1-1 North Anna 10 MILE Vicinity.ai

LEGEND

- Lake Anna
- Waste Heat Treatment Facility

FIGURE 2.1-1
North Anna Power Station,
10-Mile Vicinity Map
LICENSE RENEWAL APPLICATION

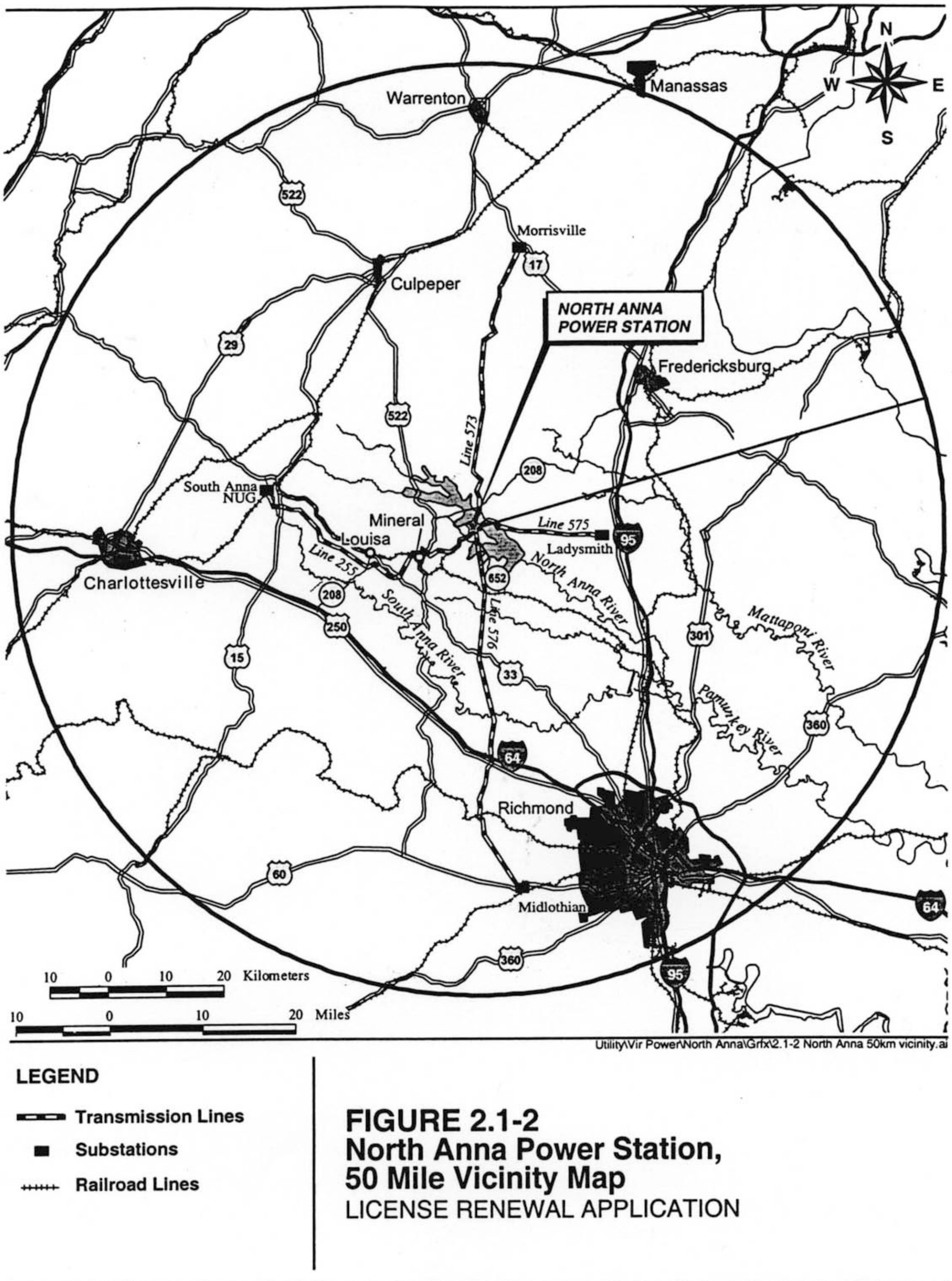


FIGURE 2.1-2
North Anna Power Station,
50 Mile Vicinity Map
LICENSE RENEWAL APPLICATION

United States Department of the Interior
FISH AND WILDLIFE SERVICE
Ecological Services
6669 Short Lane
Gloucester, Virginia 23061

April 27, 2000

Mr. Tony Banks
Virginia Power
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, Virginia 23060

Greetings:

The U.S. Fish and Wildlife Service has received your request to review the attached project for potential impacts to federally listed or proposed endangered and threatened species and designated critical habitat in Virginia pursuant to the Endangered Species Act (87 Stat. 884, as amended; 16 U.S.C. 1531 et seq.). Attached are lists of species with federal status and species of concern that have been documented or may occur in the county(s) where your project is located. These lists were prepared by this office and are based on information obtained from previous surveys for rare and endangered species.

Due to the limited staff in this office, we are unable to review projects in a timely manner. Therefore, we request that you send the attached project to the following state agencies for review:

Plant Protection
Virginia Department of Agriculture and Consumer Services
P.O. Box 1163
Richmond, VA 23218
(804) 786-3515

Virginia Department of Game and Inland Fisheries
Environmental Services Section
P.O. Box 11104
Richmond, VA 23230
(804) 367-1000

Virginia Department of Conservation and Recreation
Division of Natural Heritage
217 Governor Street, 3rd Floor
Richmond, VA 23219
(804) 786-7951

It is recommended that all of the agencies named above review the project because each maintains a different database and has differing expertise and/or regulatory responsibility. **IF ANY OF THESE AGENCIES DETERMINES THAT YOUR PROJECT MAY IMPACT A FEDERALLY LISTED, PROPOSED, OR CANDIDATE SPECIES OR CRITICAL HABITAT, PLEASE CONTACT THIS OFFICE; OTHERWISE, FURTHER CONTACT WITH THIS OFFICE IS NOT NECESSARY.**

If you have any questions or need further assistance, please contact William Hester of this office at (804) 693-6694, extension 134.

Sincerely,

Karen L. Mayne

Karen L. Mayne
Supervisor
Virginia Field Office

Enclosures

Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, Virginia 23060

RECEIVED APR 2000 GLOUCESTER

VIRGINIA POWER

April 12, 2000

Ms. Karen Mayne, Supervisor
Virginia Field Office
US Fish & Wildlife Service
6669 Short Lane
Gloucester, VA 23061

Re: Surry and North Anna Power Stations Nuclear License Renewal and Environmental Reports

Dear Ms. Mayne:

Virginia Power is preparing applications for renewing the operating licenses for its Surry and North Anna Power Stations. We intend the applications to be consistent with US Fish & Wildlife Service's requirements and with the priorities of our communities. As part of the license renewal process, the Nuclear Regulatory Commission (NRC) requires that applicants identify adverse impacts to threatened and endangered species resulting from continued operation of the facility or from refurbishment activities associated with license renewal. The operation of Surry and North Anna Power Stations has had no adverse impact on any threatened or endangered species. In addition, no future operational or refurbishment activities are planned which would invalidate this conclusion.

As a matter of course, the NRC will request an informal consultation with your agency regarding our actions. The time frame for the NRC consultation request is anticipated to be in the second half of 2001, following a September applications submittal. To assist you in responding to this request, I have enclosed figures for each station site depicting local and regional vicinities.

It is our expectation that, by contacting you early in the application process, we can identify any questions needing to be addressed or data needed to facilitate a smooth and expeditious NRC consultation. We will appreciate your notifying us of your comments and of any information or actions required of Virginia Power in advance to assist in meeting shared objectives.

Please contact Mr. Tony Banks at (804) 273-2170 should you or your staff have any questions or comments.

Respectfully,

P. F. Faggert

P. F. Faggert, Vice-President and
Chief Environmental Officer

Enclosure: Figures of Surry and North Anna vicinities

cc:

4-00ERconsult1.ltr

KEY

LE - federally listed endangered.

LT - federally listed threatened.

PE - federally proposed endangered.

PT - federally proposed threatened.

EX - believed to be extirpated in Virginia.

LE(S/A) - federally listed endangered due to similarity of appearance to a federally listed speci

LT(S/A) - federally listed threatened due to similarity of appearance to a federally listed species

C - candidate species; the U.S. Fish and Wildlife Service has enough information to list the species as threatened or endangered, but this action is precluded by other listing activities.

SOC - species of concern; those species that have been identified as potentially imperiled or vulnerable throughout their range or a portion of their range. These species are not protected under the Endangered Species Act.

C2 - former U.S. Fish and Wildlife Service category 2 candidate species.

G - global rank; the species rarity throughout its total range.

G1 - extremely rare and critically imperiled with 5 or fewer occurrences or very few remaining individuals; or because of some factor(s) making it especially vulnerable to extinction.

G2 - very rare and imperiled with 6 to 20 occurrences or few remaining individuals; or because of some factor(s) making it vulnerable to extinction.

G3 - either very rare and local throughout its range or found locally (abundantly at some of its locations) in a restricted range; or vulnerable to extinction because of other factors. Usually fewer than 100 occurrences are documented.

G_T_ - signifies the rank of a subspecies or variety. For example, a G5T1 would apply to a subspecies of a species that is demonstrably secure globally (G5) but the subspecies warrants a rank of T1, critically imperiled.

G_Q - The taxon has a questionable taxonomic assignment.

SPOTSYLVANIA COUNTY, VIRGINIA
Federally Listed, Proposed, and Candidate Species

SCIENTIFIC NAME	COMMON NAME	STATUS
INVERTEBRATES		
Alasmidonta heterodon	Dwarf wedge mussel	LE
VASCULAR PLANTS		
Isotria medeoloides[1]	Small whorled pogonia	LT

Species of Concern

INVERTEBRATES		
Elliptio lanceolata	Yellow lance	G3
Lasmigona subviridis	Green floater	G3
Sigara depressa	Virginia Piedmont water boatmen	G1G3
Speyeria idalia	Regal fritillary	G3
NON-VASCULAR PLANTS		
Sphagnum carolinianum	Carolina peatmoss	G3

[1]This species has been documented in an adjacent county and may occur in this county.

March 22, 1999
Prepared by U.S. Fish and Wildlife Service, Virginia Field Office

SURRY COUNTY, VIRGINIA
Federally Listed, Proposed, and Candidate Species

SCIENTIFIC NAME	COMMON NAME	STATUS
BIRDS		
Haliaeetus leucocephalus[1]	Bald eagle	LT
PLANTS		
Aeschynomene virginica	Sensitive joint-vetch	LT

Species of Concern

INVERTEBRATES		
Speyeria diana	Diana fritillary	G3
Stygobromus araeus	Tidewater interstitial amphipod	G2
VASCULAR PLANTS		
Carex decomposita	Epiphytic sdege	G3
Chamaecrista fasciculata var. macrosperma	Marsh senna	G5T2
Desmodium ochroleucum	Creamflower tick-trefoil	G2G3
Rudbeckia heliopsidis[2]	Sun-facing coneflower	G2
Trillium pusillum var. virginianum	Virginia least trillium	G3T2

[1]Nesting occurs in this county; concentrated shoreline use has been documented on the James River.

[2]Surveys needed within 5-miles of Prince George County species location.

March 22, 1999

Prepared by U.S. Fish and Wildlife Service, Virginia Field Office

U.S. Fish & Wildlife Service

Bald Eagle

Haliaeetus leucocephalus

Description - The bald eagle occurs throughout the United States. It is a large bird-of-prey with dark brown plumage, a white head and tail, and a yellow bill, feet, and eyes. Juvenile eagles generally have a dark brown body, sometimes with white patches on the tail, belly, and underwings. The head and tail become completely white when full adult plumage is reached at four to five years of age.

Life History - The majority of Virginia's eagle population is found on the coastal plain. The bald eagle breeding season begins in mid-November when large nests are built (or the previous year's nest is repaired) usually in loblolly pine trees that are in close proximity to water. Eagles lay one to three eggs between mid-January and late March. In March, most eggs hatch and by June or July most young have fledged. However, the young will continue to use the nest for several weeks. In Virginia, during the summer and winter months, juvenile and nonbreeding adult eagles congregate along large rivers in areas with abundant food and little human disturbance. During the day, these eagles feed and perch along the river shoreline. In late afternoon, they move inland to roost either singly or communally. Roosts are typically located away from human disturbance and near water and a food source. Bald eagles feed primarily on fish, but will also eat carrion, waterfowl, small mammals, snakes, and turtles.

U.S. Fish and Wildlife Service
Virginia Field Office
6669 Short Lane
Gloucester, Virginia 23061
(804) 693-6694
http://www.fws.gov
August 1999

Conservation - The bald eagle was federally listed as an endangered species in the Chesapeake Bay Region on March 11, 1967. On July 12, 1995, the bald eagle was reclassified to threatened throughout the 48 lower states because the population had increased due to the banning persistent pesticides, habitat protection, and other recovery activities. On July 6, 1999, the bald eagle was proposed for removal from the list of endangered and threatened wildlife in the lower 48 states. This action was proposed because the available data indicated that this species has recovered. The recovery is due in part to habitat protection and management actions initiated under the Endangered Species Act. It is also due to reduction in levels of persistent pesticides occurring in the environment. If and when the eagle is no longer protected by the Endangered Species Act, it will still be protected by the Bald and Golden Eagle Protection Act, Migratory Bird Treaty Act, and state laws. Until the eagle is officially delisted, it will continue to receive protection pursuant to the Endangered Species Act. Bald eagles in the Chesapeake Bay are increasing. However, habitat destruction through urban and residential development and human disturbance in nesting, roosting, and foraging habitats continue to be a threat.

What You Can Do To Help - If you know of a bald eagle nest on or near property proposed for clearing, development, or logging please contact one of the following agencies for assistance:

Virginia Department of Game and
Inland Fisheries
P.O. Box 11104
Richmond, Virginia 23230
(804) 367-1000

U. S. Fish and Wildlife Service
6669 Short Lane
Gloucester, Virginia 23061
(804) 693-6694

References

U.S. Fish and Wildlife Service. 1990. Chesapeake Bay Region bald eagle recovery plan: first revision. Newton Corner, Massachusetts.

U.S. Fish and Wildlife Service. 1999. Proposed rule to remove the bald eagle in the lower 48 states from the list of endangered and threatened wildlife. Federal Register 64(128): 36453-36464.

Watts, B.D., K.W. Cline, and M.A. Byrd. 1994. The bald eagle in Virginia: An information booklet for land planners. The Center for Conservation Biology, College of William and Mary, Williamsburg, Virginia.

U.S. Fish & Wildlife Service

Sensitive Joint-Vetch

Aeschynomene virginica

© M. Rollins

Description - The sensitive joint-vetch is an annual legume native to the eastern United States. Populations currently exist in Maryland, New Jersey, North Carolina, and Virginia. The historical range for the species extended to Delaware and Pennsylvania. In Virginia, populations are found along the Potomac, Mattaponi, Pamunkey, Rappahannock, Chickahominy, and James Rivers and their tributaries. This plant usually attains a height of three to six feet in a single growing season, but may grow as tall as eight feet. The flowers are yellow, streaked with red and the fruit is a pod, turning dark brown when ripe.

Life History - The joint-vetch occurs in fresh to slightly brackish tidal river systems, within the intertidal zone where populations are flooded twice daily. It typically occurs at the outer fringe of marshes or shores; its presence in marsh interiors may be a result of nutrient deficiencies, ice scouring, or muskrat herbivory. The sensitive joint-vetch is found in localities where plant diversity is high and annual species are prevalent. Bare to sparsely vegetated substrates appear to be a habitat feature of critical importance for establishment and growth of this species. Plants flower from July through September and into October in some years. Fruits are produced from July through late October, concurrent with flowering.

Conservation - The sensitive joint-vetch was federally listed as a threatened species on June 19, 1992. Threats to the species include sedimentation, competition from non-native plant species, dams, dredging, filling, recreational activities, shoreline stabilization, shoreline structures, road and bridge construction, commercial and residential development, water withdrawal projects, water quality degradation, agricultural practices, introduced pest species, mining, timber harvest, over-visitation, declines in muskrat populations, rise in sea level (this may also be a result of natural cycles), and collection. Natural threats are often identified with disturbances, such as wave and ice action associated with severe storm events, competition, herbivory, channel migration, sea level rise and natural sedimentation processes. Adequate habitat conservation for this species will only be achieved through on-site protection of marshes supporting plant populations when coupled with protection of the natural ecological processes responsible for creating and maintaining habitat for the sensitive joint-vetch.

What You Can Do To Help - Avoid the use of herbicides in or near waterways. If you are planning construction or stabilization activities along the shoreline in one of the counties indicated on the attached map, please contact the U.S. Fish and Wildlife Service.

References

Davison, S.E. and L.P. Bruderle. 1984. Element stewardship abstract for *Aeschynomene virginica* - sensitive joint vetch. The Nature Conservancy. Arlington, Virginia.

Hershner, C. and J.E. Perry. 1987. Population status of potentially threatened vascular plants from coastal plain tidal rivers in Virginia. College of William and Mary, Virginia Institute of Marine Science, Gloucester Point, Virginia.

Rouse, G.D. 1994. Sensitive joint-vetch life history and habitat study, 1993 Field Season, Mattaponi and Rappahannock River systems, Virginia. Schnabel Environmental Services. Richmond, Virginia.

U.S. Fish and Wildlife Service. 1995. Sensitive joint-vetch (*Aeschynomene virginica*) recovery plan. Hadley, Massachusetts.

U.S. FISH & WILDLIFE SERVICE

U.S. Fish and Wildlife Service
Virginia Field Office
6669 Short Lane
Gloucester, Virginia 23061
(804) 693-6694
http://www.fws.gov
August 1999

U.S. Fish & Wildlife Service

Dwarf Wedge Mussel

Alasmidonta heterodon

B. Windsor

Description - The dwarf wedge mussel has a spotty distribution in Atlantic coast drainage rivers and their tributaries from Canada to North Carolina. It is a small mussel whose shell rarely exceeds 1.5 inches in length. The shell outline is ovate or trapezoidal. The female shell is shorter, trapezoidal, and inflated in the back whereas the male shell is elongate, compressed, and ovate. The outer shell layer is brown to yellowish-brown, with greenish rays in young or pale-colored specimens. This mussel is unique in that it has two lateral teeth on its right valve and only one tooth on its left valve (opposite of all other North American mussel species).

Life History - The dwarf wedge mussel lives in shallow to deep rivers and creeks of various sizes where the current is slow to moderate. This mussel lives on muddy sand, sandy, and gravel stream bottoms that are nearly silt free. Like other freshwater mussels, this species is a filter feeder. It feeds on plankton collected from water that is passed over its gills. Reproduction occurs sexually. Females carry eggs in their gills. During spawning, the male releases sperm into the water column and the sperm is taken into the female through the gills. The resulting larvae (known as glochidia) are released from the female into the water column and must attach to a fish host to survive. While attached to the fish host, development of the glochidia continues. Once metamorphosis is complete, the juvenile mussel drops off the fish host and continues to develop on the stream bottom. Fish hosts for this species include the mottled sculpin (*Cottus bairdi*), slimy sculpin (*Cottus cognatus*), tessellated darter (*Etheostoma olmstedi*), and johnny darter (*Etheostoma nigrum*).

Conservation - The dwarf wedge mussel was federally listed as an endangered species on March 14, 1990. The decline of this species is due to human degradation of habitat and water quality which have resulted in the continuing decline and subsequent loss of this species from previously occupied habitat. Threats to the species include agricultural, domestic, organic, and industrial pollution; impoundments that destroy habitat and cause silt deposits, low oxygen levels, and fluctuations in water levels and temperatures of the flooded area; and erosion and siltation from land clearing and construction of bridges or roads.

What You Can Do To Help - If you reside on property that borders a stream or other waterway, avoid using chemicals or fertilizers. To help control erosion and reduce runoff, maintain a buffer of natural vegetation along streambanks. Install fencing to prevent livestock from entering streams to reduce trampling of mussels, siltation, and input of waste products. Protecting water quality is the most effective way to conserve mussels.

To find out more about the dwarf wedge mussel contact:

Virginia Department of Game and Inland Fisheries
P.O. Box 11104
Richmond, Virginia 23230
(804) 367-1000

References

Michaelson, D.L. and R.J. Neves. 1995. Life history and habitat of the endangered dwarf wedgemussel *Alasmidonta heterodon* (Bivalvia:Unionidae). Journal of the North American Benthological Society 14(2):324-340.

U.S. Fish and Wildlife Service. 1993. Dwarf wedge mussel (*Alasmidonta heterodon*) recovery plan. Hadley, Massachusetts.

U.S. Fish and Wildlife Service
Virginia Field Office
6669 Short Lane
Gloucester, Virginia 23061
(804) 693-6694
http://www.fws.gov
August 1999

Dominion Generation
5000 Dominion Boulevard, Glen Allen, VA 23060

Dominion

January 25, 2001

Mr. Eric Davis
US Department of the Interior
Fish & Wildlife Service
Ecological Services
6669 Short Lane
Gloucester, VA 23061

Re: Dominion's Surry and North Anna Power Stations Nuclear License Renewal

Dear Mr. Davis:

This correspondence follows recent telephone conversations that you have had with Dr. Jud White of Dominion's Environmental Policy and Compliance Department, about nuclear license renewal for Surry and North Anna Power Stations. Please find enclosed for your review Draft Environmental Reports for the license renewal application, one for each station, and a copy of previous Fish and Wildlife Service correspondence.

Following the correspondence from Ms. Mayne (April 27, 2000), Dominion has been working with the appropriate Commonwealth of Virginia agencies to discuss select Environmental Report issues. There is a meeting tentatively scheduled in early February 2001 to receive comments from those agencies' reviews. You are also invited to attend that meeting. We can correspond again to confirm your interest as that meeting date gets set. If you prefer to comment without attending the meeting in Richmond, receiving those comments or questions are welcome as well.

We regard our cooperative relationships with jurisdictional agencies such as yours important in meeting regulatory requirements and shared objectives. Your interest and active participation in our license renewal efforts and potentially with the U.S. Nuclear Regulatory Commission (NRC) later this year are appreciated.

Should you have questions regarding any of the enclosed information, please contact me at 804/273-2170, or Dr. Jud White at 804/273-2948.

Thank you for your attention to the matters presented herein.

Sincerely,

TB Copy

Tony Banks, MPH, CHMM

Cc: J. W. White, EP&C
LR file

Pamela F. Faggert
Vice President and Chief Environmental Officer
5000 Dominion Boulevard, Glen Allen, VA 23060
Phone: 804-273-3467

Dominion

November 13, 2000

Mr. Frank Fulgham, Program Manager
Office of Plant and Pest Services
Virginia Department of Agriculture and
Consumer Services
P.O. Box 1163
Richmond, VA 23218

Re: Meeting at Dominion Generation (Virginia Power) to discuss Surry and North Anna Power Stations Nuclear License Renewal

Dear Mr. Fulgham:

This correspondence follows recent telephone conversations about nuclear license renewal for Surry and North Anna Power Stations. Your attendance is requested at an informational luncheon meeting, scheduled for December 12, 2000, at Dominion's Innsbrook Technical Center in Glen Allen, Virginia (directions are enclosed). The primary focus of the meeting is to discuss environmental requirements for license renewal and potential expectations of state agencies. Your attendance at this meeting and active participation in our license renewal efforts with the U.S. Nuclear Regulatory Commission (NRC) are considered vital to the application process, and are appreciated.

Dominion Generation will submit an application for renewal of the Surry and North Anna operating licenses next summer, 2001. A key component of the application is an Environmental Report that addresses specific issues, and which also pertains to your agency's interests and functions. We regard our cooperative relationships with jurisdictional agencies such as yours important in meeting regulatory requirements and shared objectives.

In preparation of the meeting and for your review, please find enclosed written sections of the Environmental Reports that apply to your area of responsibility. Additional components of these reports will be presented and reviewed at the meeting.

Should you have questions regarding any of the enclosed information prior to December 12, please contact Mr. Tony Banks at 804/273-2170, or Mr. Jud White at 804/273-2948. If you are unable to attend, or you would like to bring an additional staff member to the meeting, we request that you notify us to accommodate meal planning.

Thank you for your attention to the matters presented herein.

Sincerely,

P. F. Faggert

P. F. Faggert

Enclosures: List of Attendees
Directions to Innsbrook
✓ ER documentation

11-00 agency mtg.ltr.doc 11/08/00

Agency attendees:	-Mr. John Davey, Director Dept. of Conservation and Recreation -Ms. Ethel Eaton, Archeologist Senior Dept. of Historic Resources -Mr. Frank Fulgham, Program Manager Dept. of Agriculture and Consumer Services -Mr. Robert Grabb, Chief Virginia Marine Resources Commission -Mr. Joe Hassell, Environmental Manager Dept. of Environmental Quality -Mr. Robert Hicks, Director Dept. of Health -Ms. Ellie Irons, Program Manager Dept. of Environmental Quality -Mr. Charlie Sledd, Director Dept. of Game and Inland Fisheries
Company attendees:	-Mr. Bill Corbin, Project Manager License Renewal Project -Mr. Mike Henig, Supervisor License Renewal Project -Mr. Jud White, Manager Environmental Policy and Compliance -Mr. Rick Zuercher, Manager Nuclear Public Affairs -Mr. Tony Banks, Environmental Lead License Renewal Project -Mr. Jon Cudworth, Consultant License Renewal Project -Mr. David R. Lewis, Counsel License Renewal Project
Cc:	-Ms. Leslie Hartz, Vice President Nuclear Engineering and Services -Mr. William Matthews, Vice President Nuclear Operations -Mr. Carter Cooke, Environmental Compliance Coordinator North Anna Power Station -Mr. Mike Holland, Environmental Compliance Coordinator Surry Power Station -Mr. David Brickley, Agency Director Dept. of Conservation and Recreation -Mr. David Paylor, Program Coordinator Dept. of Environmental Quality -Mr. Alexander Wise, Director Dept. of Historic Resources -Mr. Bill Woodfin, Director Dept. of Game and Inland Fisheries

11-00 agency mtg.ltr.doc 11/08/00

Dominion Generation (Virginia Power) Nuclear License Renewal Luncheon Meeting

Time: 11:00 to 2:00

Location: Innsbrook Technical Center Ground Floor Conference Room A

Directions to Innsbrook:

From Richmond via I-64 West -

First exit past Gaskins Rd, Exit onto Broad St (250 E) back toward Richmond, Make first left at the traffic light onto Dominion Blvd, Follow the road around the S-curve to enter the center Parking Lot near the flagpoles.

Enter the central glass doors, proceed to the Security Desk, where they will direct you to the Ground Floor Conference Room A.

From Richmond via Broad St (250 W) –

Proceed past main entrance road to Innsbrook (Cox Rd) to the next traffic light (Dominion Blvd), Make right onto Dominion Blvd, Follow the road around the S-curve to enter the center Parking Lot near the flagpoles.

Enter the central glass doors, proceed to the Security Desk, where they will direct you to the Ground Floor Conference Room A.

11-00 agency mtg.ltr.doc 11/08/00

Dominion

Pamela F. Faggert
Vice President and Chief Environmental Officer
5000 Dominion Boulevard, Glen Allen, VA 23060
Phone: 804-273-3467

November 13, 2000

Mr. John Davey, Director
Planning and Recreation Resources
Virginia Department of Conservation and Recreation
203 Governor Street, Suite 326
Richmond, VA 23219

Re: Meeting at Dominion Generation (Virginia Power) to discuss Surry and North Anna Power Stations Nuclear License Renewal

Dear Mr. Davey:

This correspondence follows recent telephone conversations about nuclear license renewal for Surry and North Anna Power Stations. Your attendance is requested at an informational luncheon meeting, scheduled for December 12, 2000, at Dominion's Innsbrook Technical Center in Glen Allen, Virginia (directions are enclosed). The primary focus of the meeting is to discuss environmental requirements for license renewal and potential expectations of state agencies. Your attendance at this meeting and active participation in our license renewal efforts with the U.S. Nuclear Regulatory Commission (NRC) are considered vital to the application process, and are appreciated.

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Thank you for your attention to the matters presented herein.

Sincerely,

P. F. Faggert

P. F. Faggert

Enclosures: List of Attendees
Directions to Innsbrook
✓ER documentation

11-00 agency mtg.ltr.doc 11/08/00

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Cc:	-Ms. Leslie Hartz, Vice President Nuclear Engineering and Services -Mr. William Matthews, Vice President Nuclear Operations -Mr. Carter Cooke, Environmental Compliance Coordinator North Anna Power Station -Mr. Mike Holland, Environmental Compliance Coordinator Surry Power Station -Mr. David Brickley, Agency Director Dept. of Conservation and Recreation -Mr. David Paylor, Program Coordinator Dept. of Environmental Quality -Mr. Alexander Wise, Director Dept. of Historic Resources -Mr. Bill Woodfin, Director Dept. of Game and Inland Fisheries

11-00 agency mtg.ltr.doc 11/08/00

Dominion Generation (Virginia Power) Nuclear License Renewal Luncheon Meeting

Time: 11:00 to 2:00

Location: Innsbrook Technical Center Ground Floor Conference Room A

Directions to Innsbrook:

From Richmond via I-64 West -

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Enter the central glass doors, proceed to the Security Desk, where they will direct you to the Ground Floor Conference Room A.

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Enter the central glass doors, proceed to the Security Desk, where they will direct you to the Ground Floor Conference Room A.

11-00 agency mtg.ltr.doc 11/08/00

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Ecological Services
6669 Short Lane
Gloucester, VA 23061

rec'd 3/19/01
T. Banks

March 13, 2001

Memorandum

To: David Sutherland, Chesapeake Bay Field Office

Through: Branch Chief, Endangered Species Division (Mary Ratnaswamy)

From: Supervisor, Virginia Field Office

Subject: Consultation with U.S. Nuclear Regulatory Agency

The Virginia Field Office (VAFO) received a letter from Dominion Generation dated January 25, 2001. Dominion Generation, through the U.S. Nuclear Regulatory Commission, plans to apply to renew the licenses at two nuclear power plants in Virginia: Surry and North Anna Power Stations. Dominion Power's Environmental Reports are enclosed.

VAFO reviewed both projects for potential impacts to federally listed species. The North Anna Power Station license renewal will not affect federally listed species. The Surry Power Station license renewal may affect the bald eagle, *Haliaeetus leucocephalus*. An eagle nest, VASU96-04, is approximately one mile from the power station. Furthermore, the power station is located within an eagle shoreline use area.

VAFO understands that the Chesapeake Bay Field Office (CBFO) will now take the lead on this project. Enclosed is the latest version of the eagle guidelines for Virginia as prepared by VAFO and the Virginia Department of Game and Inland Fisheries (VDGIF). VAFO and VDGIF will continue to provide support to CBFO.

If you have any questions or need further assistance, please contact Eric Davis at (804) 693-6694 ext. 104.

J. Eric Davis Jr.
for Karen L. Mayne

Enclosures

cc: VDGIF (Don Schwab)
Dominion Generation (Tony Banks)

BALD EAGLE PROTECTION GUIDELINES FOR VIRGINIA

Prepared by

Virginia Field Office
U.S. Fish and Wildlife Service
6669 Short Lane
Gloucester, VA 23061
804-693-6694

Virginia Department of Game and Inland Fisheries
P.O. Box 11104
Richmond, VA 23230
804-367-1000

Last Updated: 5/15/2000

INTRODUCTION

The Virginia Department of Game and Inland Fisheries (VDGIF) and the U.S. Fish and Wildlife Service (USFWS) are responsible for the conservation and management of the bald eagle (*Haliaeetus leucocephalus)* throughout Virginia. To provide consistent management of the bald eagle in Virginia, the VDGIF and USFWS have developed the following general guidelines. These guidelines indicate the zones around eagle nests, night roosts, and shoreline use areas in which the provisions of various laws and their implementing regulations may apply. All proposed activities that may affect or result in the take of a bald eagle in Virginia will be evaluated by the VDGIF and USFWS on a case-by-case basis, using site-specific information. The recommendations given in these guidelines may be modified as necessary in individual cases, based on a number of factors such as topography, existing forest canopy, and observed reactions of eagles to disturbance at a particular site.

In Virginia, adult bald eagles typically remain on or near their breeding territories year round. Nest building and repair begins as early as November and peaks in mid-winter, but may occur during any month of the year. Courtship flights and related mating behavior are most frequently observed during January and February, and eggs are usually laid between mid-January and late March. Most eggs hatch between early March and early May and eaglets stay in the nest for 11 to 12 weeks after hatching. Most young are capable of sustained flight by mid July, but remain dependent on the parents and stay in the general vicinity of the nest for several more weeks. Eagles are most sensitive to disturbance from mid-December to early July, the period when they are building their nests, incubating eggs, raising young, and while the young are learning to fly.

Virginia also has several areas along the major tidal river systems where non-breeding eagles are known to concentrate for roosting and feeding. Some of these areas are used by eagles in the summer and some are used in the winter. These eagle concentration areas are extremely important, because they are used by eagles from throughout the East Coast, as well as resident eagles.

FEDERAL LAWS PROTECTING THE BALD EAGLE

Endangered Species Act (ESA) (87 Stat. 884; 16 U.S.C. 1531 et seq.; 50 CFR Part 17) – Section 7(a)(2) requires federal agencies to ensure that any action they authorize, fund, or carry out is not likely to jeopardize the continued existence of any federally listed threatened or endangered species. If a federal agency determines that its action "may affect" a listed threatened or endangered species, the agency is required to consult with the USFWS regarding the degree of impact and measures available to avoid or minimize the adverse effects.

Section 9 of the ESA makes it illegal for any person subject to the jurisdiction of the United States to "take" any federally listed endangered or threatened species of fish or wildlife without a special exemption. "Person" is defined under the ESA to include individuals, corporations, partnerships, trusts, associations, or any other private entity; local, state, and federal agencies; or any other entity subject to the jurisdiction of the United States. Under the ESA, "take" means to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, collect, or to attempt to engage in any such conduct. Harm is further defined to include significant habitat modification or degradation that results in death or injury to listed species by significantly impairing essential behavior patterns such as breeding, feeding, or sheltering. Harass is defined as actions that create the likelihood of injury to listed species to such an extent as to significantly disrupt normal behavior patterns which include, but are not limited to, breeding, feeding, or sheltering.

Section 10(a)(1)(B) of the ESA establishes an incidental take permit provision that authorizes the USFWS, under some circumstances, to permit the taking of federally listed wildlife by private individuals if such taking is "incidental to, and not the purpose of carrying out otherwise lawful activities."

Bald and Golden Eagle Protection Act (54 Stat. 250, as amended; 16 U.S.C. 668; 50 CFR Part 22) – This 1940 Act prohibits the taking of bald and golden eagles or their nests and eggs. Under this Act, taking is defined as "to pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest or disturb."

Migratory Bird Treaty Act (MBTA) (40 Stat. 755, as amended; 16 U.S.C. 701 et seq.; 50 CFR

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Parts 10, 20, 21) – This Act, passed into law in 1918, was established to protect migratory birds and prohibits the taking of any migratory bird, nest, egg, or part, except as permitted by the USFWS. The prohibitions under this law and its implementing regulations generally include activities or attempted activities that pursue, hunt, shoot, wound, kill, trap, capture, possess, or collect any migratory bird species and their nests and eggs.

VIRGINIA LAWS AND REGULATIONS PROTECTING THE BALD EAGLE

Virginia's Endangered Species Act (§29.1-563 - §29.1-570) – This law provides that VDGIF is the state regulatory authority over federally or state listed endangered or threatened fish and wildlife in the Commonwealth, defining *fish or wildlife* as "*. . . any member of the animal kingdom, vertebrate or invertebrate, except for the class Insecta, and includes any part, products, egg, or the dead body or parts thereof.*" It prohibits the taking, transportation, processing, sale, or offer for sale within the Commonwealth of any fish or wildlife listed as a federally endangered or threatened species, except as permitted by the Board of Game and Inland Fisheries for zoological, educational, scientific, or captive propagation for preservation purposes.

The Act further authorizes the Board to adopt the federal list of endangered and threatened species, to declare by regulation that species not listed by the federal government are endangered or threatened in Virginia, and to prohibit by regulation the taking, transportation, processing, sale, or offer for sale of those species. Implementing regulations passed pursuant to this authority (4 VAC 15-20-130 through 140) further define "take" and other terms similarly to the federal Endangered Species Act.

Federal Endangered Species Act Cooperative Agreement – Federally listed endangered or threatened species also are placed under VDGIF jurisdiction via a cooperative agreement signed in 1976 with the USFWS pursuant to Section 6 of the ESA. This Cooperative Agreement recognizes VDGIF as the Virginia agency with regulatory and management authority over federally listed or threatened animals excluding insects, and provides for federal/state cooperation regarding the protection and management of those species.

State Protection of Wildlife Species – In addition to these endangered species laws, regulations, and cooperative agreement, the Code of Virginia (§29.1-521) and VDGIF regulations (4 VAC 15-30-10) provide legal protection to all native birds and to their nests, eggs, and young.

GENERAL CONSERVATION RECOMMENDATIONS

The following recommendations are *generally* appropriate to avoid take of bald eagles, and thus avoid the need for any state or federal permits or Section 7 consultation (if a federal action is involved). Activities and projects that do not conform with these recommendations will likely

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require some form of approval or permit from the VDGIF and/or USFWS, and should always be coordinated with these agencies to ensure compliance with state and federal laws.

Guidelines for Eagle Nests

Primary Management Zone – This is defined as the area 750 feet (229 meters) in radius around an occupied nest. The precise size of this zone should depend on site conditions and the individual eagles' tolerance for human activity. The following activities should not occur at any time within this zone:

- land clearing, clear cutting, mining, and other habitat modification activities;
- development of residential, recreational, agricultural, commercial, or industrial structures, power lines, roads, trails, or any other construction activity;
- use of chemicals toxic to wildlife, such as pesticides and herbicides.

The following activities should not occur during the breeding/nesting season (December 15 - July 15), unless the nest is determined to be unoccupied in a particular year (VDGIF usually has this information after March 31):

- maintenance of existing buildings and roads;
- use of motorized vehicles and heavy equipment;
- aircraft flyovers within 1000 vertical feet of the ground;
- human entry and activities, including recreation, such as hiking, camping, picnicking, hunting, fishing, boating, jet skiing, etc.;
- loud noise generating activities, including blasting.

Limited selective timber harvest to within 300 feet (91 meters) of the nest tree, after consultation with the VDGIF/USFWS biologists, may be possible *outside* the breeding/nesting season, if a forest canopy is maintained.

Secondary Management Zone – This is defined as the area from 750 feet (229 meters) to 1,320 feet (400 meters) in radius around an occupied nest. The precise size of this zone should depend on site conditions and the individual eagles' tolerance for human activity. Restrictions in this zone are necessary to minimize disturbance that could compromise eagle use of the nest. Most activities within this zone should be restricted during the breeding/nesting season, and allowable activities should be determined by VDGIF/USFWS on a case-by-case basis. Development and vegetation clearing should be minimized and line-of-sight vegetation buffers to the nest should be maintained. The following activities generally should not occur at any time within this zone:

- development of multi-story buildings; high density housing (construction of single story, low density residential houses may be acceptable); large commercial, industrial, or agricultural facilities; high traffic roads; and facilities that would generate loud noise;

- use of chemicals toxic to wildlife, such as pesticides and herbicides.

The following activities should not occur during the breeding/nesting season (December 15 - July 15), unless the nest is determined to be unoccupied in a particular year (VDGIF usually has this information after March 31):

- aircraft flyovers within 1000 vertical feet of the ground;

- construction activities;

- recreational activities that generate loud noise, such as motorized boats, jet skis, etc.;

- other loud noise generating activities, including blasting.

Outside of the breeding/nesting season, most other activities can be conducted within the secondary management zone as determined on a case-by-case basis by VDGIF/USFWS.

Nest/Nest Tree Removal – The eagle nest and the tree/structure in which it is located cannot be removed as long as any portion of the nest remains in the tree/structure.

Abandoned Nest – For three consecutive nesting seasons after the last season in which the nest was occupied (and any portion of the nest is present), the primary and secondary management zone guidelines described above should be followed. In April of the third year after the nest was last occupied, a determination of nest abandonment should be made by VDGIF/USFWS before restricted activities within these zones are undertaken.

Guidelines for Eagle Concentration Areas

Management zones for communal night roosting sites and documented high use shoreline foraging areas generally should be applied the same as for nests. Seasonal occupation varies depending on the specific roost or shoreline area, but is generally defined as summer (May 1 - September 30) and winter (November 1 - February 28). Appropriate human use and building/land disturbance restrictions should be determined on a case-by-case basis by VDGIF/USFWS.

DEFINITIONS

Active nest – A nest that is seen to have an adult eagle in incubating or brooding position, or that contains eggs or young.

Breeding/nesting season – December 15 through July 15 in Virginia. This period includes courtship, nest building/repairs, breeding, incubation, raising young, late nesting, and fledgling use of the nest.

Fledgling – Young bird capable of flight.

Occupied nest – A nest where there is evidence that a pair of adult eagles was present during the breeding season, even if there is no evidence that eggs were laid.

Productive/successful nest – An eagle nest that fledges young.

REFERENCES

Cline, K. 1985. Bald eagles in the Chesapeake: A management guide for landowners. National Wildlife Federation, Washington, D.C.

Therres, G. D., M. A. Byrd, and D. S. Bradshaw. 1993. Effects of development on nesting bald eagles: Case studies from Chesapeake Bay. Transactions of the 58th North American Wildlife and Natural Resources Conference. Pg. 62-69.

U.S. Fish and Wildlife Service. 1987. Habitat management guidelines for the bald eagle in the southeast region. Third revision. Atlanta, GA.

Watts, B.D., K.W. Cline, and M.A. Byrd. 1994. The bald eagle in Virginia: An information booklet for land planners. Center for Conservation Biology, College of William and Mary, Williamsburg, VA.

Dominion Generation
5000 Dominion Boulevard, Glen Allen, VA 23060

Dominion

February 6, 2001

Ms. Carrie McDaniel, Fisheries Biologist
National Marine Fisheries Service
Protected Resources Division
1 Blackburn Dr
Gloucester, MA 01930

Re: Dominion's Surry Power Station Nuclear License Renewal

Dear Ms. McDaniel:

This correspondence follows our recent telephone conversation regarding nuclear license renewal for Dominion's Surry and North Anna Power Stations, and previous contact with the NMFS office in Hampton, VA (April 2000, January 2001). Please find enclosed for your review and comment, applicable sections of the Draft Environmental Reports for the license renewal application. One is provided for each station though Surry may be the only site in a location of interest.

We intend the application for license renewal to be consistent with requirements of the National Marine Fisheries Service and with the priorities of our communities. As part of the license renewal process, the U.S. Nuclear Regulatory Commission (NRC) requires that applicants identify adverse impacts to threatened and endangered species resulting from continued operation of the facility or from refurbishment activities associated with license renewal. There are no changes in operations or refurbishment activities planned which would invalidate the conclusion we have thus far, that there are no adverse impacts on aquatic species.

As a matter of course, the NRC may request an informal consultation with your agency regarding our actions. The time frame for this NRC request is anticipated to be in the second half of 2001, following our late spring application submittal.

We regard our cooperative relationships with jurisdictional agencies such as yours important in meeting regulatory requirements and shared objectives. Your interest and active participation in our efforts and potentially with the NRC later this year are appreciated. It is our expectation that by contacting you at this point in the process, we can identify any questions needing to be addressed prior to submittal. We respectfully request and appreciate correspondence to that effect, as well as if there are no additional data needed for your concurrence with our conclusion.

Should you have questions regarding any of the enclosed information, please contact me at 804/273-2170 (or tony_banks@dom.com), or Dr. Jud White at 804/273-2948 (or judson_white@dom.com).

Thank you for your attention to the matters presented herein.

Sincerely,

Tony Banks

Tony Banks, MPH, CHMM

Cc: J. W. White, EP&C
LR file

Enclosures: ER documentation

02-01 ER/NMFSltr.doc 02/06/01

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
NORTHEAST REGION
One Blackburn Drive
Gloucester, MA 01930

MAR 23 2001

Mr. Tony Banks, MPH, CHMM
Dominion Generation
5000 Dominion Boulevard
Glen Allen, VA 23060

Dear Mr. Banks:

This letter is in response to your inquiry on February 6, 2001, requesting information on the presence of any federally listed threatened or endangered species and/or designated critical habitat for listed species in the vicinity of Dominion's Surry Power Station, Glen Allen, Virginia. Dominion Generation is applying for nuclear license renewal as required by the U.S. Nuclear Regulatory Commission (NRC) renewal process. The renewal process requires all applicants to identify adverse impacts to threatened or endangered species that may result from continued operation of the facility or refurbishment activities associated with renewal.

Potential spawning habitat for shortnose sturgeon has been thought to occur in the James River, but there have been no reports of shortnose sturgeon in this river system. However, Atlantic sturgeon, a candidate species under the Endangered Species Act of 1973, has been documented in the vicinity of the proposed project. Nevertheless, no federally listed or proposed threatened or endangered species and/or designated critical habitat for listed species under the jurisdiction of the National Marine Fisheries Service are known to exist in the project area. No further consultation pursuant to Section 7 of the Endangered Species Act of 1973, as amended, is required. If, however, project plans change or new information becomes available that changes the basis for this determination, then consultation should be reinitiated.

Sincerely,

Mary Colligan

Mary Colligan
Acting Assistant Regional Administrator
for Protected Resources

File Code: 1514 - 05(A), nsp

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Virginia Institute of Marine Science
School of Marine Science
P.O. Box 1346
Gloucester Point, Virginia 23062 USA
804/684-7000 Fax: 804/684-7097

Mr. Tony Banks, MPH, CHMM
License Renewal Project
Dominion Generation
Innsbrook Technical Center
5000 Dominion Blvd
Glen Allen, VA 23060

4 April 2001

Dear Tony,

This letter addresses the question of whether impingement and entrainment of fishes is a significant issue for Virginia Power at the Surry Power Plant, especially in regard to recent Fishery Management Plans (FMPs) of the Atlantic States Marine Fisheries Commission. In previous correspondence, I had reported to Dave Grimes (Virginia Department of Environmental Quality) that, based on my reading, there were no specific mandates in these FMPs that bear on this issue. In general, the FMPs call upon the states to ensure that water withdrawals do not result in stock declines for federally managed species. I did note that the Virginia Institute of Marine Science has no current data in the form of direct observations at the site on the impingement and/or entrainment of fishes. Further, Virginia Power is no longer required to monitor entrainment and/or impingement of fishes at the plant.

I have examined some ancillary data on the ichthyofauna in the James River that bears on the general question of potential vulnerability of federally managed species to impacts. The information consists of a five-year summary of data (1996-2000) from the VIMS Juvenile Finfish Trawl survey compiled by Patrick Geer of the VIMS Department of Fisheries Science. The table of pooled catches and a figure representing the locations of the trawl sites is attached to this letter. As you can see, a considerable sampling effort has been expended during the period and the ichthyofauna (especially the abundance and distribution of bottom-dwelling juvenile fishes) in the near-field of the Surry Nuclear Power Plant is well known. The catchability in this trawl gear of estuarine fish species varies by size (ontogeny) and species. Thus, large fishes (such as large specimens of Atlantic sturgeon or striped bass) and schooling, pelagic fishes (such as mature American shad or juvenile and adult menhaden) are not highly vulnerable to capture by the survey gear. Thus, we cannot infer much about the abundance of these fishes in the area from the trawl survey data.

Hogchoker, white perch, Atlantic croaker, bay anchovy, spot, blue catfish and weakfish make up approximately 92% of all fishes captured by the trawl gear. On the basis of their abundance in the trawl survey catches, these species might be considered the most likely to be impacted by

VIMS

entrainment on intake screens. Most are bottom fishes and three are important commercial species (Atlantic croaker, spot and weakfish). Two other commercial species captured in the trawl survey (but not in large numbers) that could be impacted by the plant are American eel (0.7% of the total catch during the 5-y period) and striped bass (0.7%).

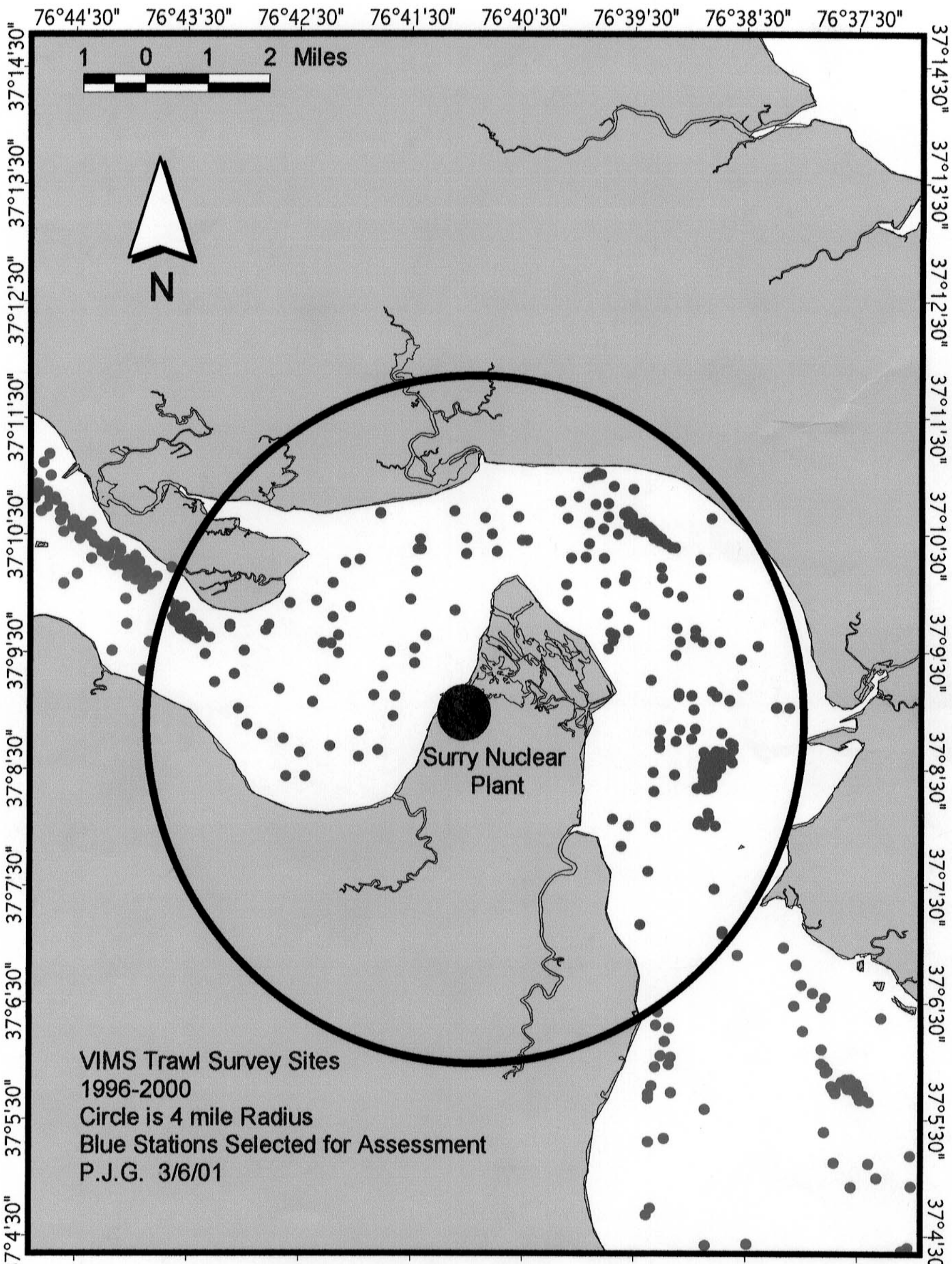
I have also examined a report of data collected by the Army Corps of Engineers (and their contractors) during a field study at the Goose Hill Channel last year. These data are proprietary and focused on channel areas where dredging occurs, however. Overall, the fishery hydro-acoustic surveys show that the fish densities are greatest in the deeper portions of the channels and along the south banks of the channels. Conventional fish sampling revealed occurrences and abundances of species that are similar to the VIMS trawl results.

The information that you provided about the operation and maintenance of traveling fish screens, especially recent repairs and upgrades to the system at the Surry Plant, suggests that the performance of these devices is better now than it originally was during the required assessments in 1980. Since the plant was in compliance with federal guidelines then, we are in agreement that this is not likely to be an issue today. Further, the available information of abundance and distribution of fishes at the site suggests that there is a low probability that water withdrawals at the plant are causing declines in stocks of federally managed species. At this point, I believe that no further action is indicated. Please let me know if you need any further assistance.

Sincerely,

John E. Olney, PhD
Associate Professor
School of Marine Science
Gloucester Point, VA 23062

Attachments
cc: Dr. Jud White, Manager
Dr. Eugene Burreson, VIMS Director for Research and Advisory Service
Mr. Patrick Geer, VIMS
Mr. Jack Travelstead, VMRC
Mr. David Grimes, DEQ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N
Surry Nuclear Plant
VIMS Trawl Survey Sites
1996-2000
Circle is 4 mile Radius
Blue Stations Selected for Assessment
P.J.G. 3/6/01

Table .

Month - All - Pooled, 1996-1999
River - James River - 4 mile radius around Surry Nuclear Plant
No. of Random Trawls Made - 177
No. of Fixed Trawls Made - 180
No. of Species - 61
Adjusted Percent of Catch Excludes Bay Anchovy and Hogchoker

Species	Number of Fish (All)	Frequency	Percent of Catch	Catch Per Trawl	Adjusted Percent of Catch	Number of Fish YOY	Average Length (mm)	Standard Error (length)	Minimum Length (mm)	Maximum Length (mm)
hogchoker	76,594	351	52.39	214.55	.	25,651	69	0.21	13	177
white perch	16,628	289	11.37	46.58	28.41	7,415	103	0.46	15	250
Atlantic croaker	15,757	302	10.78	44.14	26.92	14,577	86	0.74	9	403
bay anchovy	11,091	234	7.59	31.07	.	9,137	54	0.22	15	94
spot	7,932	191	5.43	22.22	13.55	7,709	119	0.63	19	224
blue catfish	4,815	221	3.29	13.49	8.23	1,940	185	0.93	48	477
blue crab, male	2,555	288	1.75	7.16	4.37	.	65	0.76	8	183
weakfish	2,348	138	1.61	6.58	4.01	2,275	75	0.82	17	316
blue crab, juvenile female	1,933	250	1.32	5.41	3.30	.	52	0.64	9	136
striped bass	1,032	117	0.71	2.89	1.76	908	99	2.90	15	501
American eel	960	188	0.66	2.69	1.64	.	247	1.73	113	755
gizzard shad	939	130	0.64	2.63	1.60	330	196	2.80	70	386
white catfish	782	186	0.53	2.19	1.34	103	189	2.39	48	539
channel catfish	425	131	0.29	1.19	0.73	23	289	4.28	50	594
blueback herring	367	22	0.25	1.03	0.63	366	71	1.22	54	242
blackcheek tonguefish	358	66	0.24	1.00	0.61	310	73	1.65	18	148
blue crab, adult female	352	59	0.24	0.99	0.60	.	148	0.78	110	196
jellyfish spp	254	28	0.17	0.71	0.43	.	.	.	.	.
threadfin shad	176	18	0.12	0.49	0.30	.	86	0.91	56	117
white shrimp	143	25	0.10	0.40	0.24	.	82	1.59	40	132
silver perch	133	34	0.09	0.37	0.23	121	122	2.44	52	200
brown shrimp	100	26	0.07	0.28	0.17	.	84	3.06	35	147
naked goby	72	35	0.05	0.20	0.12	.	36	0.94	17	70
Atlantic menhaden	60	32	0.04	0.17	0.10	37	146	6.96	45	321
alewife	60	26	0.04	0.17	0.10	60	108	1.62	80	137
spotted hake	56	5	0.04	0.16	0.10	56	98	1.52	68	128
blue crab, sex unknown	48	3	0.03	0.13	0.08	.	13	1.11	8	16
kingfish spp	47	24	0.03	0.13	0.08	47	104	4.19	39	141
common carp	34	15	0.02	0.10	0.06	.	564	13.93	292	725
summer flounder	28	20	0.02	0.08	0.05	21	199	15.58	93	423
banded drum	24	2	0.02	0.07	0.04	.	87	2.31	67	105
harvestfish	14	9	0.01	0.04	0.02	14	39	4.71	15	89
spottail shiner	13	2	0.01	0.04	0.02	.	86	1.90	74	96
pink shrimp	8	7	0.01	0.02	0.01	.	88	7.70	59	113
seaboard goby	7	2	0.00	0.02	0.01	.	35	1.11	32	40
Atlantic sturgeon	6	6	0.00	0.02	0.01	.	519	39.39	394	640
American shad	6	5	0.00	0.02	0.01	6	110	2.95	99	118
oyster toadfish	6	4	0.00	0.02	0.01	.	125	21.21	23	162
tessellated darter	6	3	0.00	0.02	0.01	.	67	11.05	15	94
brown bullhead	5	5	0.00	0.01	0.01	.	148	26.63	87	209
spider crab, 6 spine	4	1	0.00	0.01	0.01	.	.	.	.	.
sea lamprey	3	3	0.00	0.01	0.01	.	160	2.73	156	165
Spanish mackerel	3	2	0.00	0.01	0.01	.	112	7.36	97	120
Atlantic silverside	3	2	0.00	0.01	0.01	3	79	10.48	66	100
bluefish	2	2	0.00	0.01	0.00	.	163	38.00	125	201
Atlantic herring	2	2	0.00	0.01	0.00	.	68	9.00	59	77
butterfish	2	1	0.00	0.01	0.00	2	50	29.50	20	79
Atlantic spadefish	1	1	0.00	0.00	0.00	.	41	.	41	41
northern searobin	1	1	0.00	0.00	0.00	1	105	.	105	105
striped anchovy	1	1	0.00	0.00	0.00	1	107	.	107	107
eastern silvery minnow	1	1	0.00	0.00	0.00	.	91	.	91	91
northern pipefish	1	1	0.00	0.00	0.00	.	101	.	101	101
pumpkinseed	1	1	0.00	0.00	0.00	.	141	.	141	141
bluegill	1	1	0.00	0.00	0.00	.	55	.	55	55
skilletfish	1	1	0.00	0.00	0.00	.	49	.	49	49
roughtail stingray	1	1	0.00	0.00	0.00	.	58	.	58	58
inshore lizardfish	1	1	0.00	0.00	0.00	1	181	.	181	181
Atlantic cutlassfish	1	1	0.00	0.00	0.00	.	235	.	235	235
white mullet	1	1	0.00	0.00	0.00	.	225	.	225	225
gobie spp	1	1	0.00	0.00	0.00	.	23	.	23	23
roughneck shrimp	1	1	0.00	0.00	0.00	.	.	.	.	.
grass shrimp spp	.	94	.	.	.	.	.	.	.	.
wedge rangia clam	.	79	.	.	.	.	.	.	.	.
sand shrimp	.	68	.	.	.	.	.	.	.	.
mud crab spp	.	45	.	.	.	.	.	.	.	.
bent mussel	.	27	.	.	.	.	.	.	.	.
river shrimp	.	20	.	.	.	.	.	.	.	.
mysid shrimp	.	10	.	.	.	.	.	.	.	.
oyster, common	.	8	.	.	.	.	.	.	.	.
Amphipod spp	.	8	.	.	.	.	.	.	.	.
comb jelly spp	.	7	.	.	.	.	.	.	.	.
worm spp	.	7	.	.	.	.	.	.	.	.
little surf clam	.	4	.	.	.	.	.	.	.	.
yoldias clam spp	.	3	.	.	.	.	.	.	.	.
Tellinia clam	.	3	.	.	.	.	.	.	.	.
soft-shell clam	.	2	.	.	.	.	.	.	.	.
sea cucumber spp	.	2	.	.	.	.	.	.	.	.
All Species Combined	146,207									

Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, Virginia 23060

April 12, 2000

VIRGINIA POWER

Mr. William L. Woodfin, Director
Virginia Department of Game and
Inland Fisheries
4010 W. Broad Street
P. O. Box 11104
Richmond, VA 23230-1104

Re: Follow-up to Surry and North Anna Power Stations Nuclear License Renewal and Environmental Reports

Bill
Dear ~~Mr. Woodfin~~:

Virginia Power is now preparing the applications for renewing the operating licenses for its Surry and North Anna Power Stations. We intend the applications to be consistent with the Department of Game & Inland Fisheries' requirements and with the priorities of our communities. As part of the license renewal process, the Nuclear Regulatory Commission (NRC) requires that applicants identify adverse impacts to threatened and endangered species resulting from continued operation of the facility or from refurbishment activities associated with license renewal. It is our conclusion that the operation of Surry and North Anna Power Stations has had no adverse impact on any threatened or endangered species. In addition, no future operational or refurbishment activities are planned which would invalidate this conclusion.

As a matter of course, the NRC may request an informal consultation with your agency regarding our actions. The time frame for the NRC consultation request is anticipated to be in the second half of 2001, following a September applications submittal. To assist you in responding to this request, I have enclosed figures for each station site depicting local and regional vicinities.

It is our expectation that, by contacting you early in the application process, we can identify any questions needing to be addressed or data needed to facilitate a smooth and expeditious NRC consultation. We will appreciate your notifying us of your comments and of any information or actions required of Virginia Power in advance to assist in meeting shared objectives.

Please contact Mr. Tony Banks at (804) 273-2170 should you or your staff have any questions or comments.

Respectfully,

Pam Faggert

P. F. Faggert, Vice-President and
Chief Environmental Officer

Enclosure: Figures of Surry and North Anna vicinities

cc:

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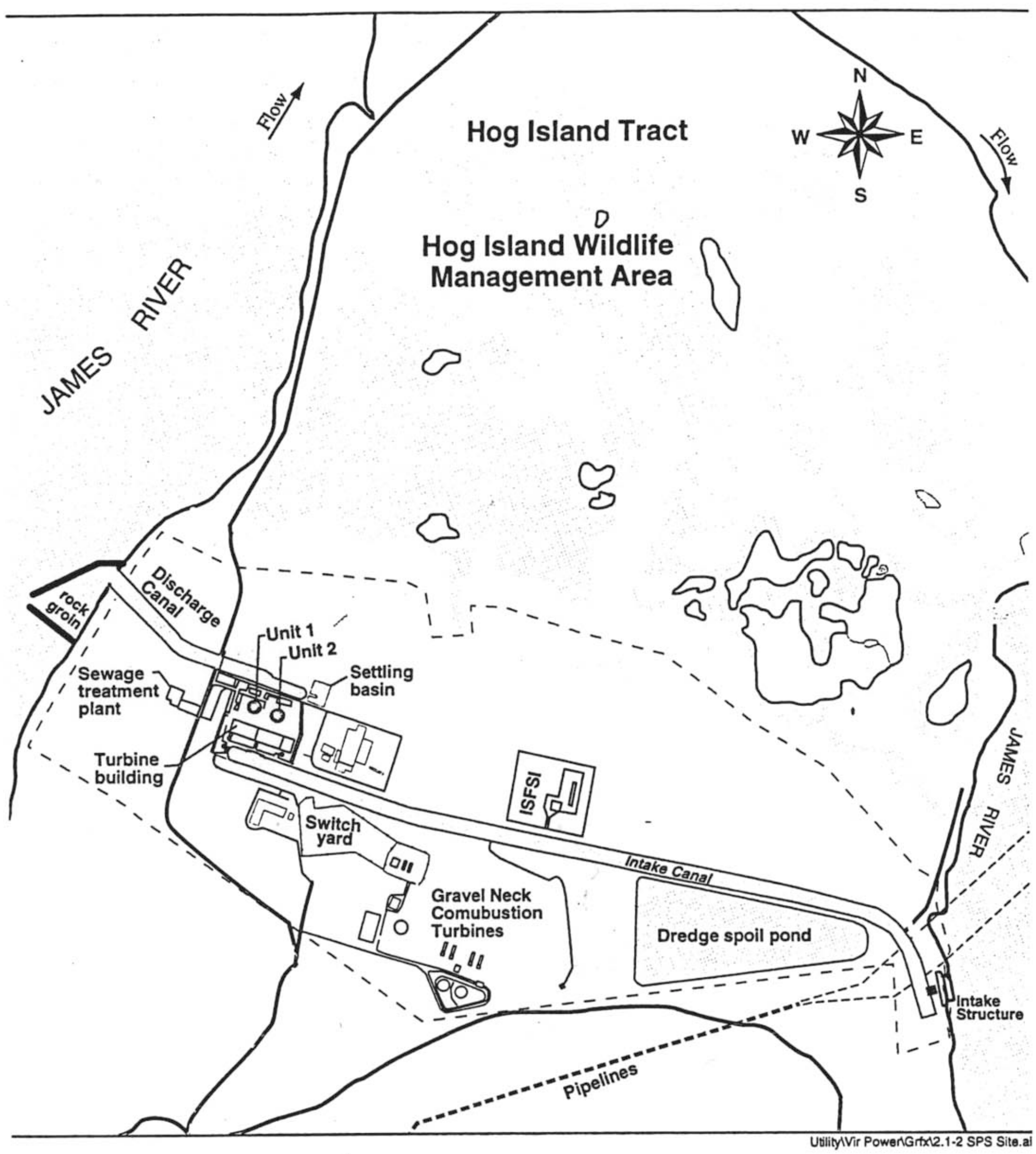
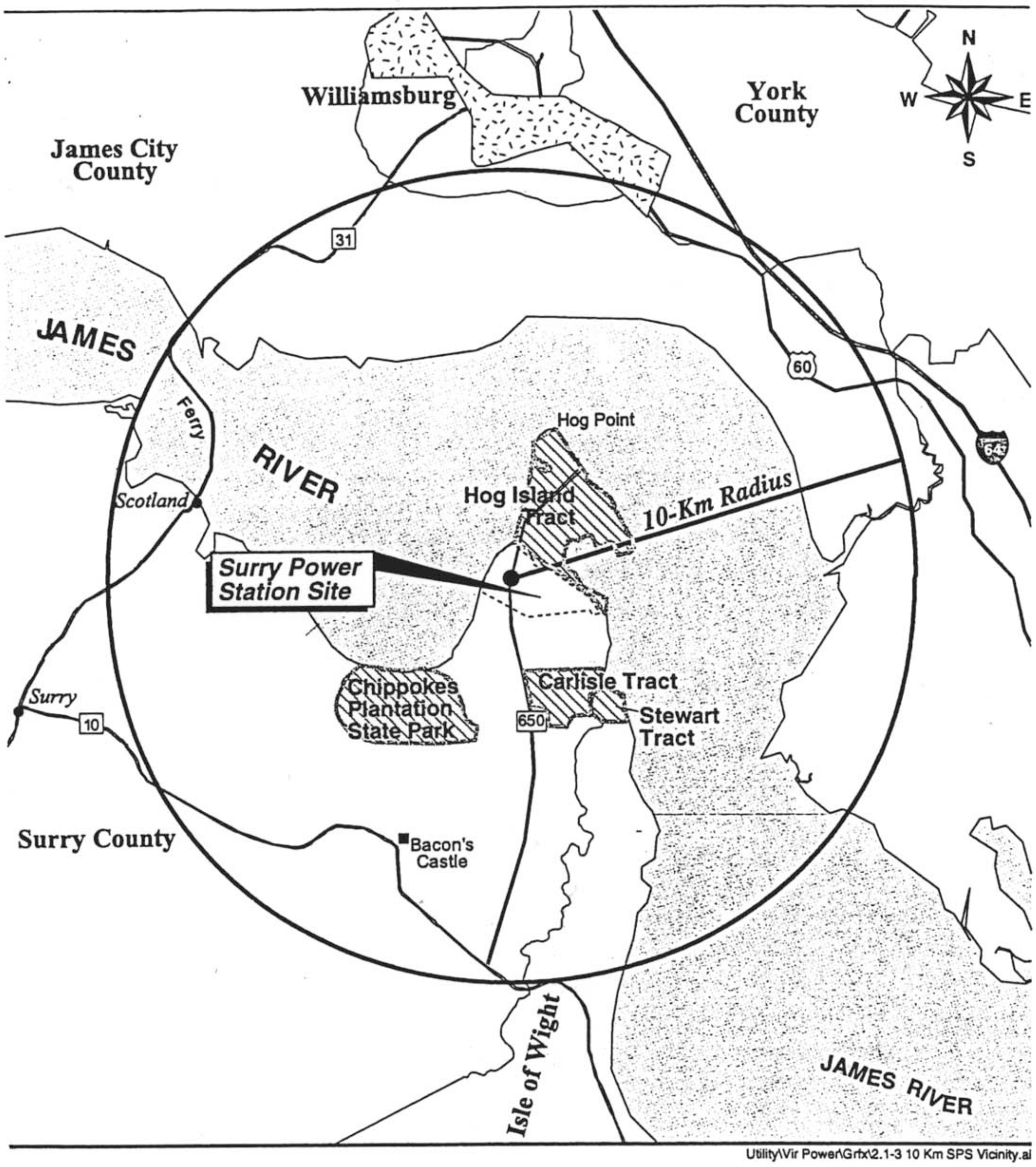


LEGEND

ISFSI Independent Spent Fuel Storage Installation

– – – Property line

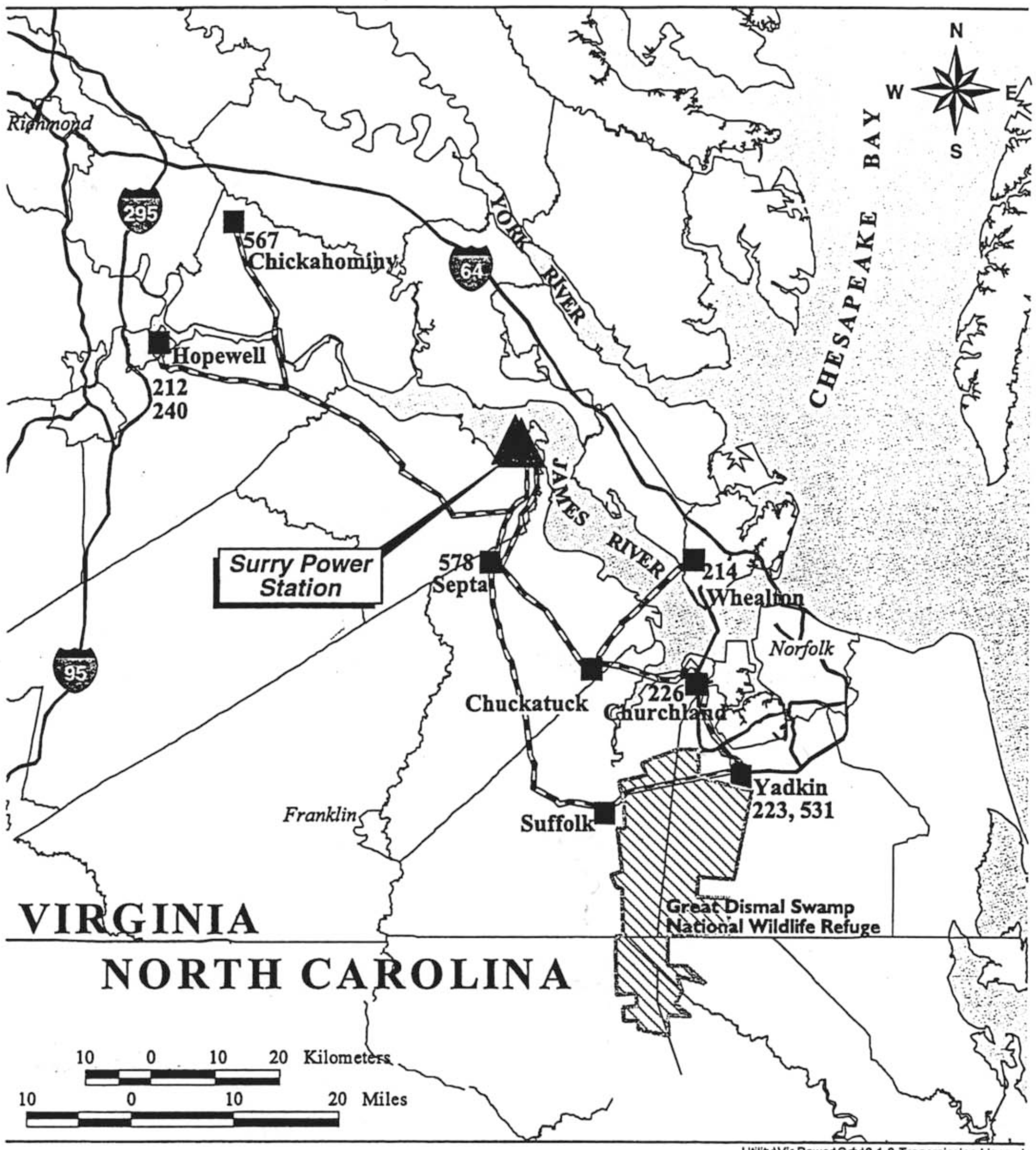
FIGURE 2.1-2
Virginia Power - SPS Site
LICENSE RENEWAL APPLICATION
Surry Power Station



LEGEND

- State Property
- Urban Areas

FIGURE 2.1-3
Virginia Power - 10 Km SPS Vicinity
LICENSE RENEWAL APPLICATION
Surry Power Station



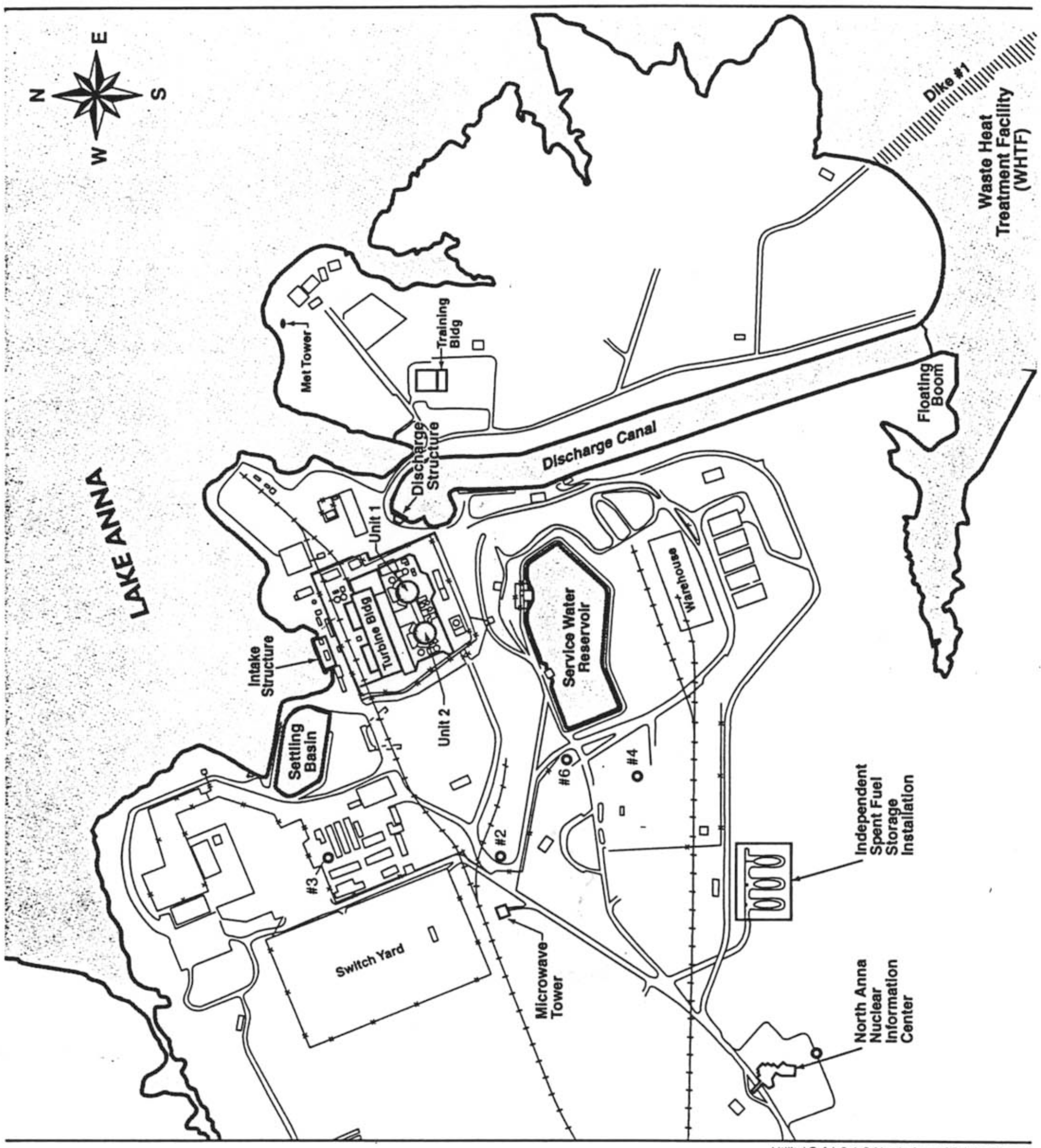
LEGEND

■ Substations

Transmission Lines

290 Line numbers noted at terminus

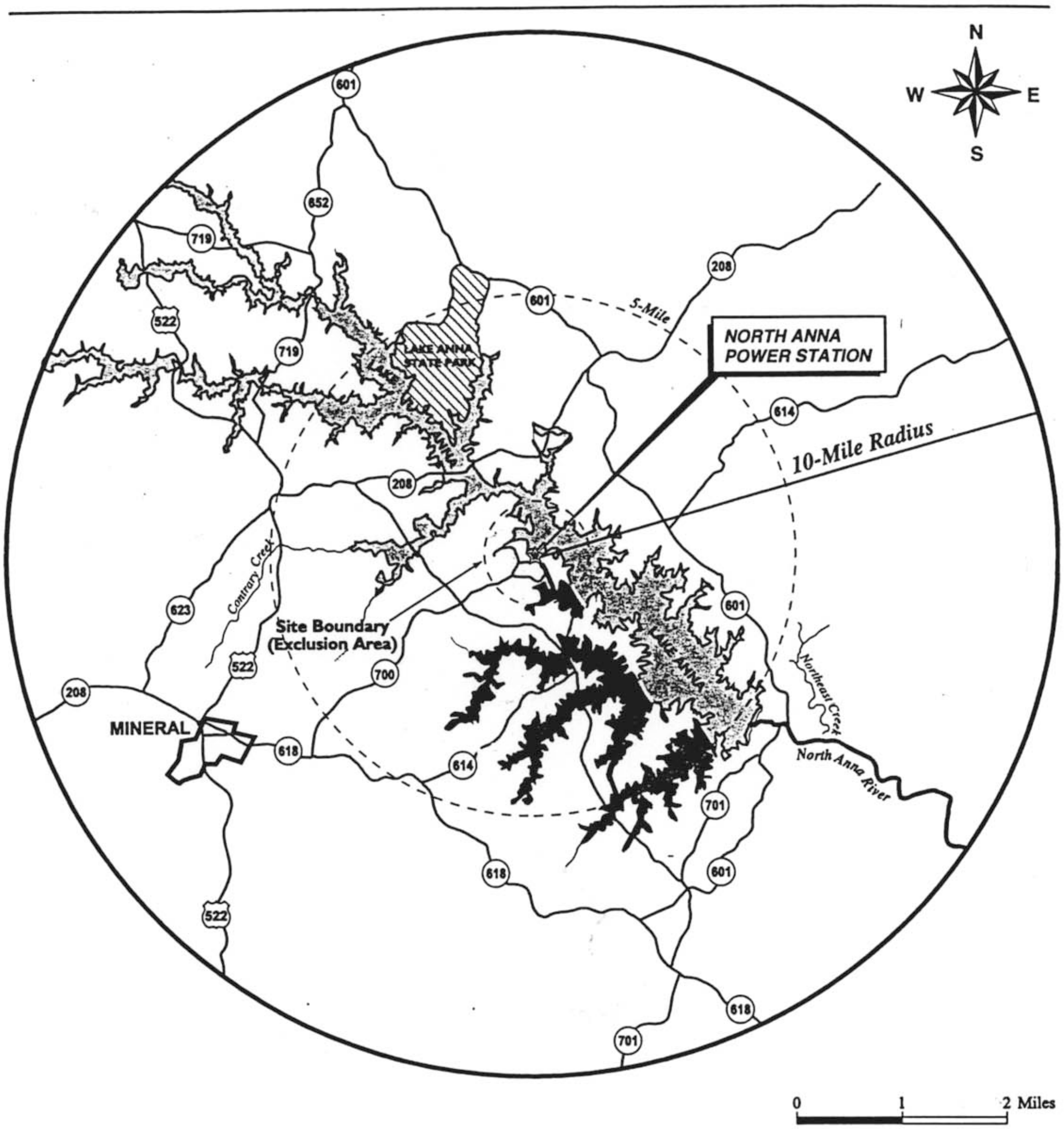
FIGURE 3.1-3
Virginia Power - Transmission Lines
LICENSE RENEWAL APPLICATION
Surry Power Station



LEGEND

- Groundwater well locations
- Railraod
- Fence

FIGURE 2.1-3
Virginia Power - North Anna Vicinity Map
LICENSE RENEWAL APPLICATION
North Anna Power Station



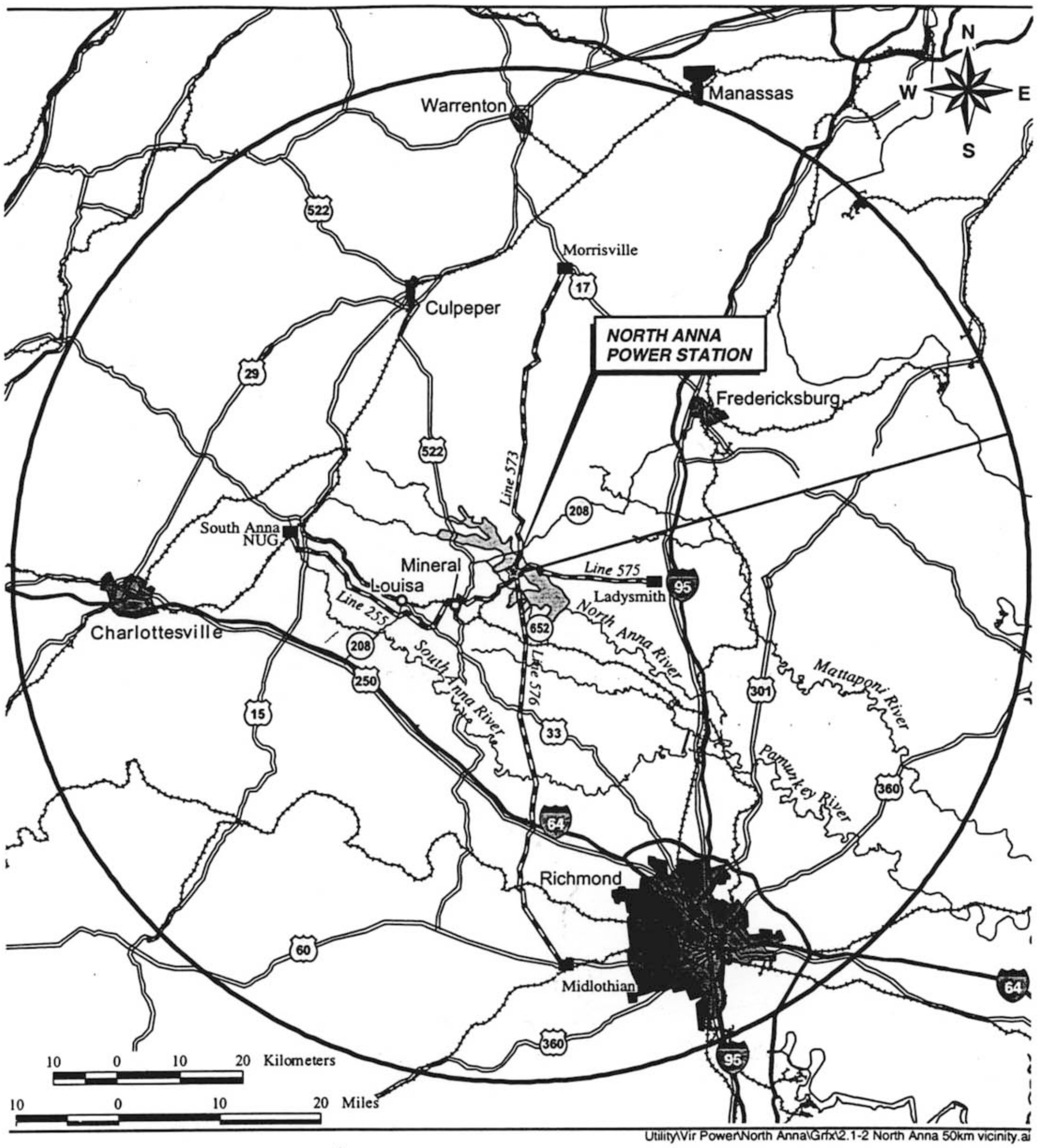
Utility\Vir Power\Grfx\2.1-1 North Anna 10 MILE Vicinity.ai

LEGEND

Lake Anna

Waste Heat Treatment Facility

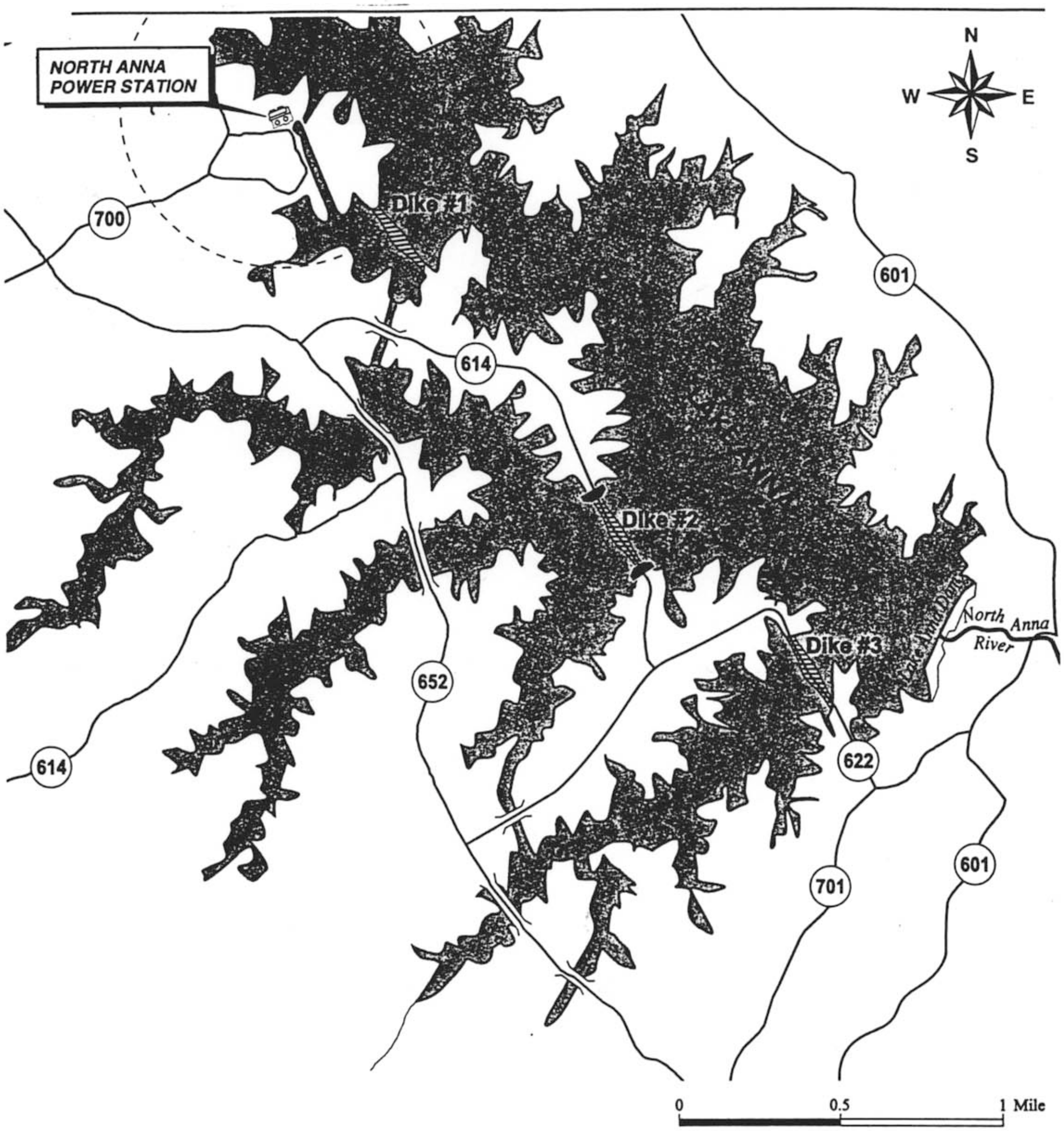
FIGURE 2.1-1
North Anna Power Station, 10-Mile Vicinity Map
LICENSE RENEWAL APPLICATION



LEGEND

Transmission Lines
Substations
Railroad Lines

FIGURE 2.1-2
North Anna Power Station,
50 Mile Vicinity Map
LICENSE RENEWAL APPLICATION



Utility\Vir Power\Grfx\x.x-x NA Waste Heat Treat Fac.ai

LEGEND

Bridge

Vehicle barrier

FIGURE 3.1-2
North Anna Power Station, Waste Heat Treatment Facility Detail Vicinity Map
LICENSE RENEWAL APPLICATION

APPENDIX D
STATE HISTORIC PRESERVATION OFFICER DETERMINATION

D-2 Letter, Faggert (VP) to Wise (Virginia Department of Historic Resources), April 12, 2000

Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, Virginia 23060

April 12, 2000

VIRGINIA POWER

Mr. Alexander Wise, Director
Virginia Department of Historic Resources
2801 Kensington Avenue
Richmond, VA 23221

Re: Surry and North Anna Power Stations Nuclear License Renewal and Environmental Reports

Dear Mr. Wise:

Virginia Power is in the process of preparing applications for renewing the operating licenses for its Surry and North Anna Power Stations. We intend the applications to be consistent with the Department of Historic Resources' requirements and with the priorities of our communities. As part of the license renewal process, the Nuclear Regulatory Commission (NRC) requires that applicants identify impacts to cultural resources, including historical and archeological sites, resulting from continued operation of the facility or from refurbishment activities associated with license renewal. We do not believe there will be any impact on these resources from our activities. In addition, no future operational or refurbishment activities are planned which would invalidate this conclusion.

As a matter of course, the NRC will request an informal consultation with your agency regarding our actions. The time frame for the NRC consultation request is anticipated to be in the second half of 2001, following a September applications submittal. To assist you in responding to this request, I have enclosed figures for each station depicting site and surrounding areas.

It is our expectation that, by contacting you early in the application process, we can identify any questions needing to be addressed or data needed to facilitate a smooth and expeditious NRC consultation. We will appreciate your notifying us of your comments and of any information or actions required of Virginia Power in advance to assist in meeting commonly shared objectives.

Following your review, a letter confirming the above conclusion would also be greatly appreciated.

Please contact Mr. Tony Banks at (804) 273-2170 should you or your staff have any questions or comments.

Respectfully,

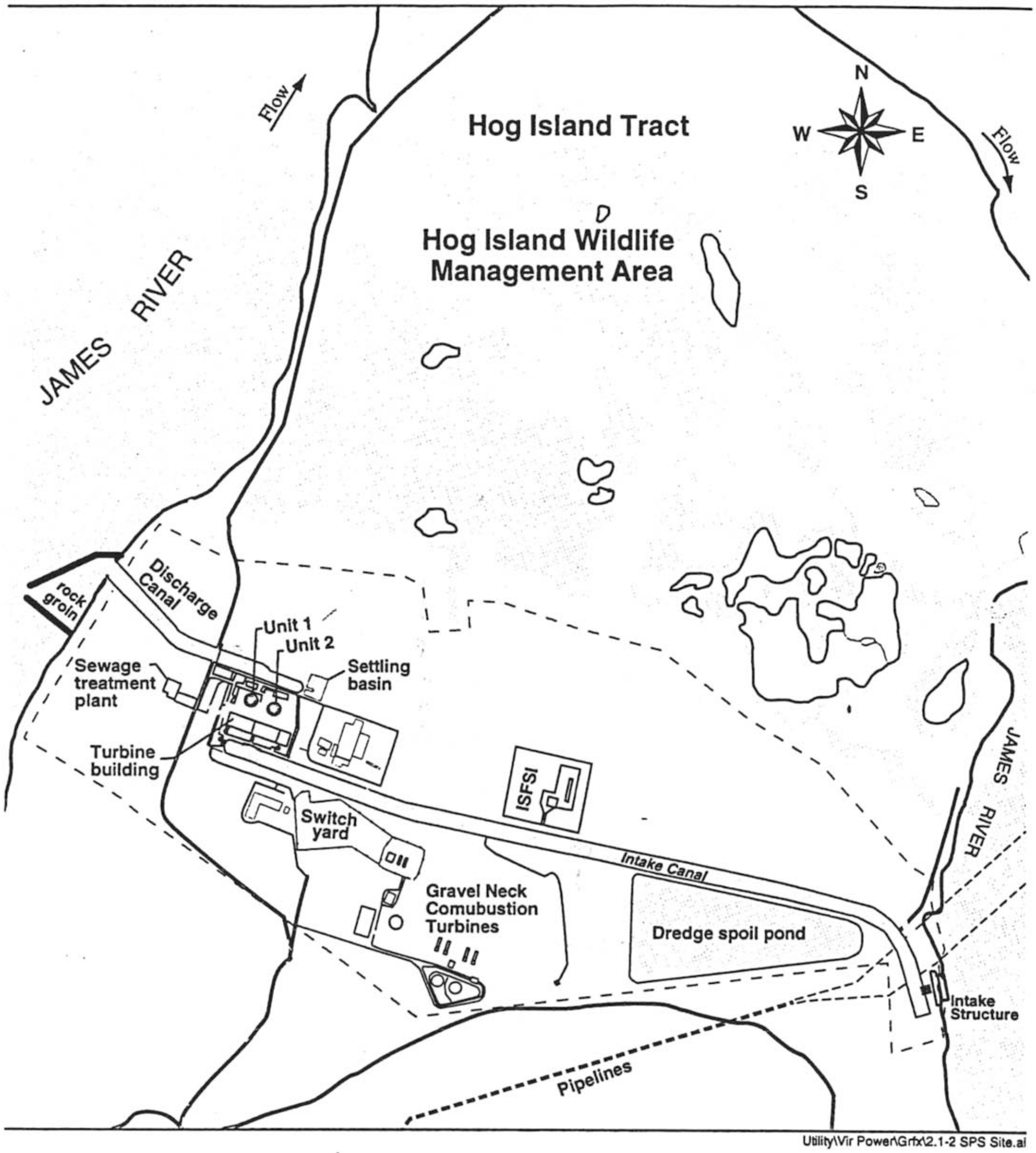
P. F. Faggert

P. F. Faggert, Vice-President and
Chief Environmental Officer

Enclosure: Figures of Surry and North Anna Sites

cc:

4-00ERconsult3.ltr

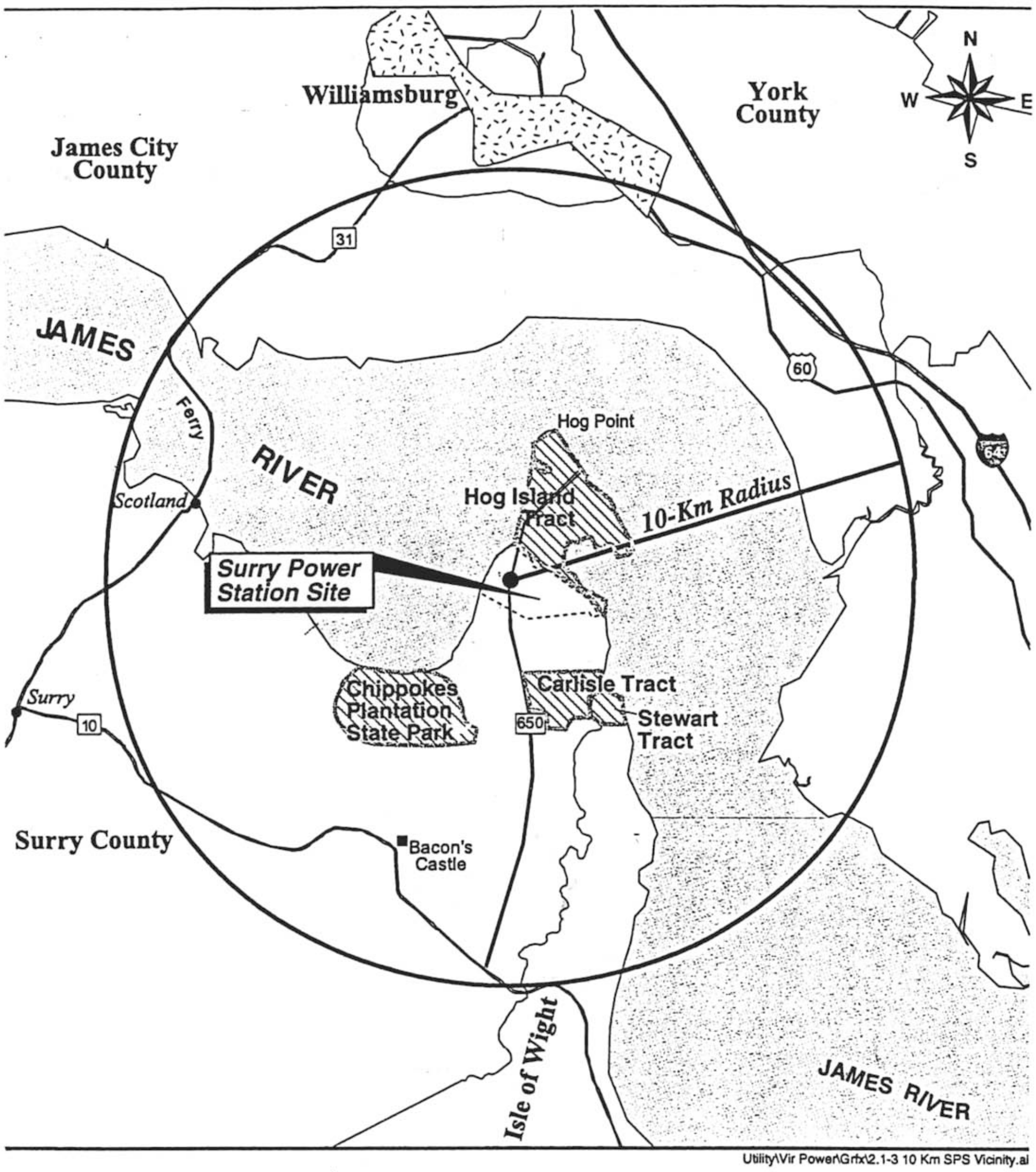


LEGEND

ISFSI Independent Spent Fuel Storage Installation

– – – Property line

FIGURE 2.1-2
Virginia Power - SPS Site
LICENSE RENEWAL APPLICATION
Surry Power Station

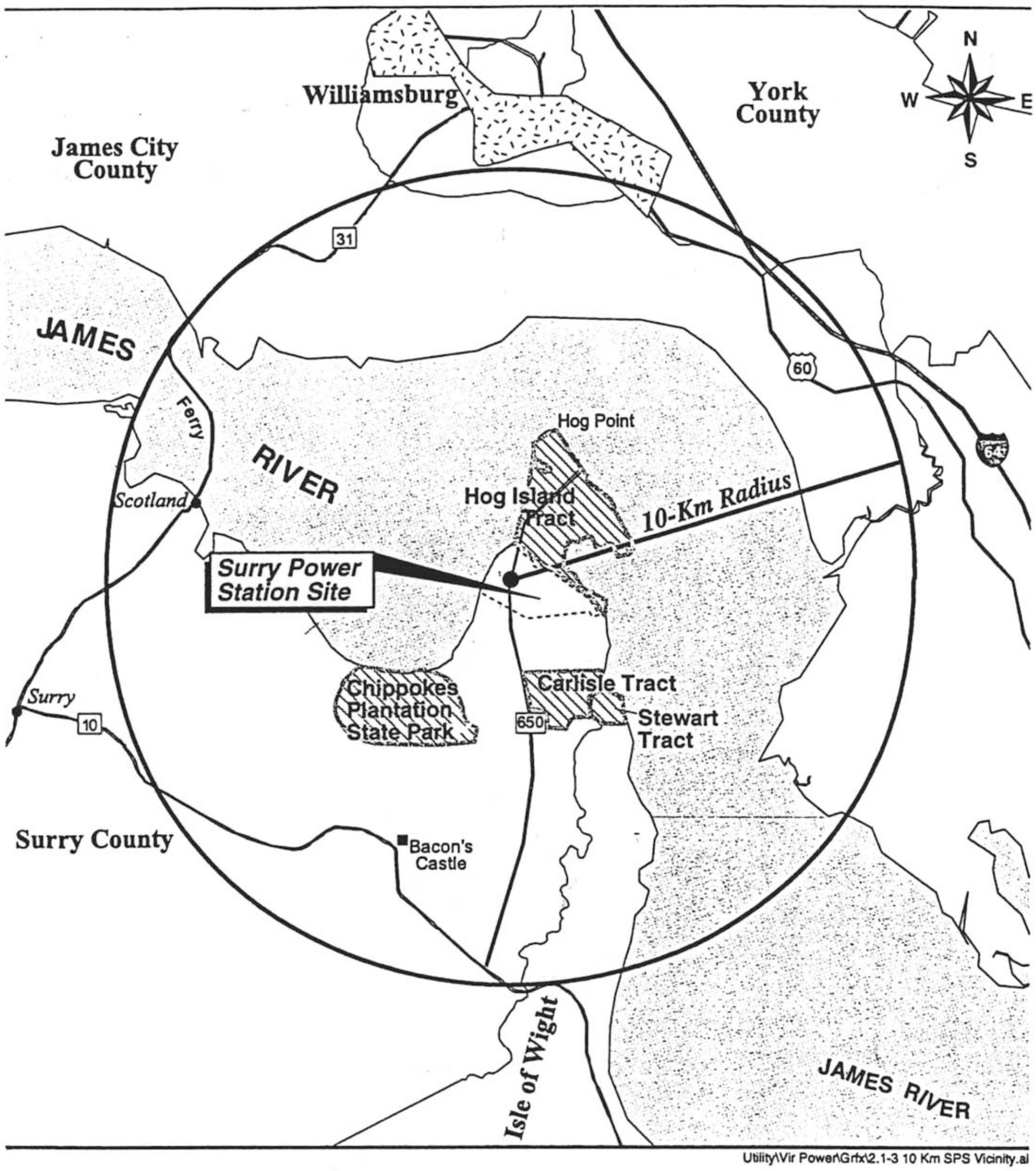


LEGEND

State Property

Urban Areas

FIGURE 2.1-3
Virginia Power - 10 Km SPS Vicinity
LICENSE RENEWAL APPLICATION
Surry Power Station



LEGEND

State Property

Urban Areas

FIGURE 2.1-3
Virginia Power - 10 Km SPS Vicinity
LICENSE RENEWAL APPLICATION
Surry Power Station

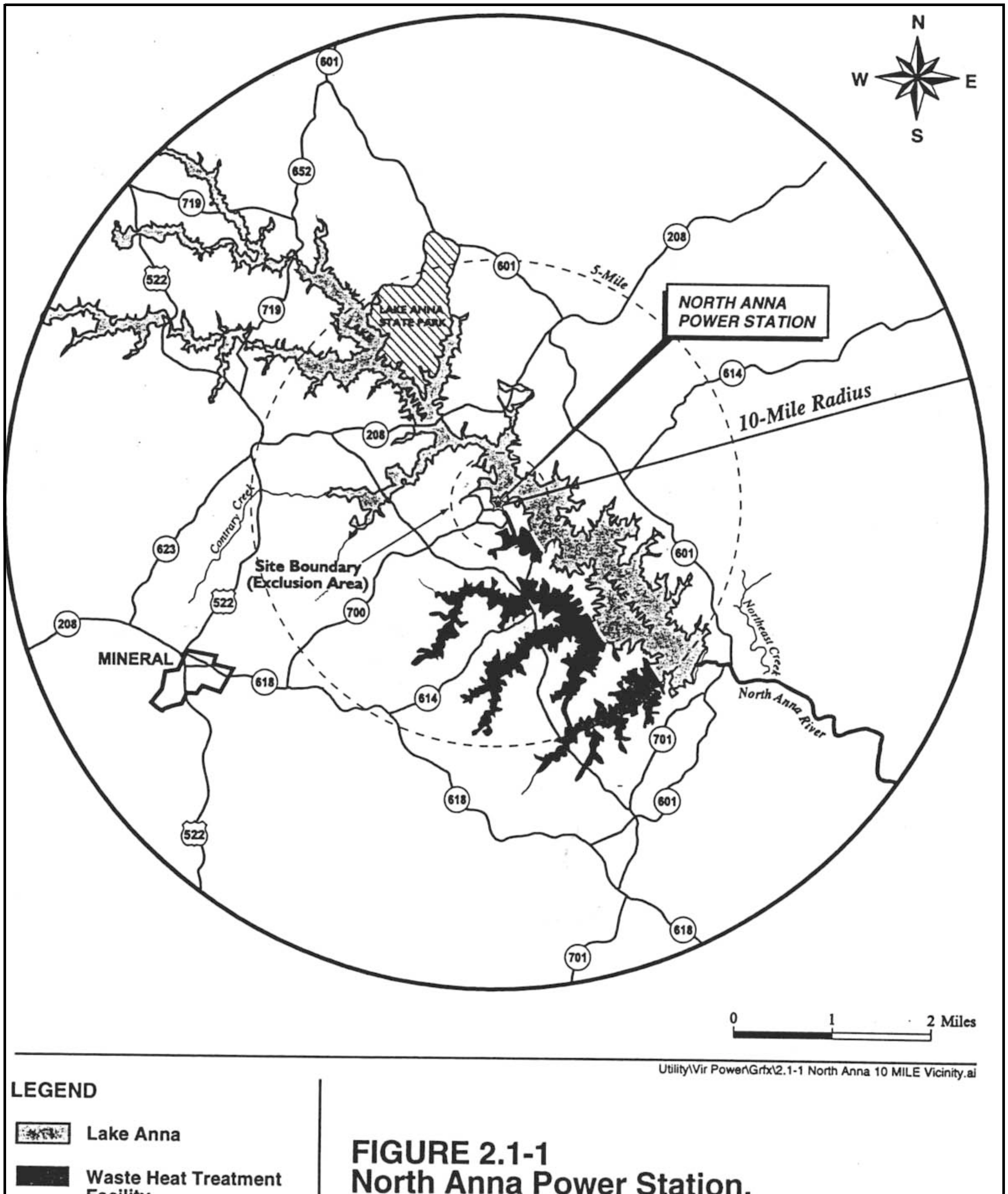


FIGURE 2.1-1
North Anna Power Station, 10-Mile Vicinity Map
LICENSE RENEWAL APPLICATION

APPENDIX E
COASTAL ZONE MANAGEMENT ACT CONSISTENCY CERTIFICATION

FEDERAL CONSISTENCY CERTIFICATION FOR FEDERAL PERMIT AND LICENSE APPLICANTS[1]

The Federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on an applicant for a Federal license to conduct an activity that could affect a state's coastal zone. The Act requires the applicant to certify to the licensing agency that the proposed activity would be consistent with the state's Federally approved coastal zone management program. The Act also requires the applicant to provide to the state a copy of the certification statement and requires the state, at the earliest practicable time, to notify the Federal agency and the applicant whether the state concurs or objects to the consistency certification. See 16 USC 1456(c)(3)(A).

The National Oceanic and Atmospheric Administration has promulgated implementing regulations that indicate that the certification requirement is applicable to renewal of Federal licenses for activities not previously reviewed by the State (15 CFR 930.51[b][1]). The Administration has also published documentation of the Virginia program (Ref. 2). Like many states, Virginia has a "networked"program, which means that it is based on a variety of existing Commonwealth authorities rather than a single law and set of regulations. The Virginia Department of Environmental Quality administers Virginia's Coastal Resources Management Program and has identified enforceable regulatory authorities that comprise the program (Ref. 3).

CONSISTENCY CERTIFICATION

Dominion has determined that U. S. Nuclear Regulatory Commission (NRC) renewal of the Surry Power Station (SPS) licenses to operate would comply with the federally approved Virginia Coastal Resources Management Program. Dominion expects SPS operations during the license renewal term to be a continuation of current operations as described below, with no changes that would affect Virginia's coastal zone.

NECESSARY DATA AND INFORMATION

Proposed Action

SPS is located on the James River in Surry County, Virginia. SPS transmission lines traverse the Virginia Counties of Prince George, Charles City, Surry, Isle of Wight, Suffolk, and Chesapeake. The Virginia Department of Environmental Quality lists all these counties as being within the Virginia Coastal Resources Management Area. Figures E-1 and E-2 show the SPS 50-mile and 6-mile regions, respectively, and Figure E-3 shows the SPS transmission line corridors.

1. This certification is patterned after the draft model certification included as Attachment 6 of Reference 1.

SPS uses uranium dioxide fuel in 2 nuclear reactors to produce steam in turbines that generate approximately 1,600 megawatts of electricity for offsite use. Dominion operates SPS Units 1 and 2 in accordance with NRC licenses DPR-32 and DPR-37, respectively. The Unit 1 license will expire May 25, 2012, and the Unit 2 license on January 29, 2013. Dominion is applying to NRC for renewal of both licenses, which would enable 20 additional years of operation (i.e., until May 25, 2032, for Unit 1 and January 29, 2033, for Unit 2).

SPS withdraws at maximum approximately 1.7 million gallons per minute of water from the James River through a shore-side intake, primarily for non-contact cooling of spent steam. Dominionperforms periodic maintenance dredging in the river in front of the intake in accordance with permits from the U. S. Army Corps of Engineers and the Virginia Marine Resources Commission (see Table E- for permit information). SPS discharges the heated effluent (11.9×10^9 British thermal units per hour) through a canal to the river. The highest discharge temperature recorded during a comprehensive 5-year study was 99.9ºF. Dominion holds a Virginia Pollutant Discharge Elimination System permit for this and other plant and stormwater discharges. In accordance with permit conditions, Dominion monitors discharge characteristics and reports results to the Virginia Department of Environmental Quality.

SPS uses approximately 220 gallons per minute of groundwater for domestic, process, and cooling purposes. The site is located within the Eastern Virginia Groundwater Management Area, an area that the Commonwealth established to better manage its groundwater resources. Dominion holds Virginia Department of Environmental Quality permit GW0003900 for the SPS groundwater appropriation. In accordance with permit conditions, Dominion monitors groundwater usage and reports results to the Virginia Department of Environmental Quality.

Dominion holds permits and annually re-registers several air emission sources at SPS. Most of these sources are emergency equipment (e.g., generators) for safe plant operation in case of loss of other power sources. As such, the sources generally operate for minimal periods of time for testing purposes.

Dominion employs approximately 880 workers at SPS, with an additional 70-110 contract and matrixed employees. Approximately 60 percent of the employees live in Isle of Wight, James City or Surry Counties, or the City of Newport News. Once or twice a year, as many as 700 additional workers are onsite during refueling outages. In compliance with NRC regulations, Dominion has analyzed the effects of SPS aging and identified activities needed to safely operate for an additional 20 years. Although Dominion does not expect to have to add additional staff to perform these activities, Dominion has assumed as many as 60 additional staff for impact analysis purposes.

Environmental Impacts

NRC has prepared a generic environmental impact statement (GEIS) on impacts that nuclear power plant operations can have on the environment (Ref. 4) and has codified its findings (10 CFR

51, Subpart A, Appendix B, Table B-1). The codification identifies 92 potential environmental issues, 69 of which NRC identifies as having small impacts and calls "Category 1"issues. NRC defines "small"as follows:

> Small – For the issue, environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purpose of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small as the term is used in this table. (10 CFR 51, Subpart A, Appendix B, Table B-1).

The NRC codification and the GEIS discuss the following types of Category 1 environmental issues:

- Surface water quality, hydrology, and use
- Aquatic ecology
- Groundwater use and quality
- Terrestrial resources
- Air quality
- Land use
- Human health
- Postulated accidents
- Socioeconomics
- Uranium fuel cycle and waste management
- Decommissioning

In its decisionmaking for plant-specific license renewal applications, absent new and significant information to the contrary, NRC will rely on its codified findings, as amplified by supporting information in the GEIS, for assessment of environmental impact from Category 1 issues (10 CFR 51.95[c][4]). For plants such as SPS that are located in the coastal zone, many of these issues involve impact to the coastal zone. Dominion has adopted by reference the NRC findings and GEIS analyses for all 51[2] applicable Category 1 issues.

The NRC regulation identifies 21 issues as "Category 2,"for which license renewal applicants must submit additional site-specific information.[3] Of these, 12 apply to SPS[4] and, like the Category 1

2. The other 18 Category 1 issues apply to design or operational features that SPS does not have (e.g., cooling towers) or to an activity, refurbishment, that Dominion will not undertake.
3. 10 CFR 51, Subpart A, Appendix B, Table B-1 also identifies 2 issues as "NA,"for which NRC could not come to a conclusion regarding categorization. Dominion believes that these issues, chronic effects of electromagnetic fields and environmental justice, do not affect the "coastal zone"as that phrase is defined by the Coastal Zone Management Act [16 USC 1453(1)].
4. The rest apply to design or operational features that SPS does not have (e.g., cooling towers) or to an activity, refurbishment, that Dominion will not undertake.

issues, could involve impact to the coastal zone. The applicable issues and Virginia Power's impact conclusions are listed below:

- Aquatic ecology
  - Entrainment of fish and shellfish in early life stages – This issue addresses mortality of organisms small enough to pass through the plant's circulating cooling water system. Dominion has conducted studies of this issue under direction of the Commonwealth and, in issuing the plant's discharge permit, the Commonwealth has approved the plant's intake structure as best available technology to minimize impact. Dominion concludes that these impacts are small during current operations and has no plans that would change this conclusion for the license renewal term.
  - Impingement of fish and shellfish – This issue addresses mortality of organisms large enough to be caught by intake screens before passing through the plant's circulating cooling water system. The studies and permit discussed above also address impingement. Dominion concludes that these impacts are small during current operations and has no plans that would change this conclusion for the license renewal term.
  - Heat shock – This issue addresses mortality of aquatic organisms caused by exposure to heated plant effluent. Dominion has conducted studies of this issue under direction of the Commonwealth and, in issuing the plant's discharge permit, the Commonwealth has determined that more stringent limits on the heated effluent are not necessary to protect the aquatic environment. Dominion concludes that these impacts are small during current operations and has no plans that would change this conclusion for the license renewal term.
- Groundwater use and quality
  - Groundwater use conflicts – This issue addresses effects that SPS groundwater withdrawals could have on offsite groundwater users. Dominion has calculated that withdrawals during the license renewal term would lower groundwater levels less than 0.5 feet in the nearest offsite well. Dominion concludes that this impact is small.
- Threatened or endangered species – This issue addresses effects that SPS operations could have on species that are listed under federal law as threatened or endangered. In analyzing this issue, Dominion has also considered species that are listed under Commonwealth of Virginia law. Several species could occur on the SPS site, in the site vicinity in the James River, or along associated transmission corridors. Dominion environmental studies and environmental protection programs have identified no adverse impacts to such species and Dominion consultation with cognizant Federal and Commonwealth agencies has identified no impacts of concern. Dominion concludes that

SPS impacts to these species are small during current operations and has no plans that would change this conclusion for the license renewal term.

- Human health
  - Electromagnetic fields, acute effects (electric shock) – This issue addresses the potential for shock from induced currents, similar to static electricity effects, in the vicinity of transmission lines. Because this strictly human-health issue does not directly or indirectly affect natural resources of concern within the Coastal Zone Management Act definition of "coastal zone"(16 USC 1453[1]}, Dominion concludes that the issue is not subject to the certification requirement.
- Socioeconomics

  As a result of its studies on managing the effects of SPS aging, Dominion expects to perform license renewal activities without adding staff. As a conservative measure, however, Dominion has assumed, for the purposes of socioeconomic impact analysis, adding as many as 60 additional employees. Dominion assumes that these employees would find housing in the same locales where current employees reside.
  - Housing – This issue addresses impacts on local housing availability that could occur as a result of Dominion adding license renewal term workers and the community gaining additional indirect jobs. NRC concluded, and Virginia Power concurs, that impacts would be small for plants located in high population areas having no growth control measures. Using the NRC definitions and categorization methodology, SPS is located in a high population area and locations where additional employees would probably live have no growth control measures. Dominion concludes that impacts during the SPS license renewal term would be small.
  - Public services; public utilities – This issue addresses impacts that adding license renewal term workers could have on public water supply systems. Dominion has analyzed public water supply availability in candidate locales and has found no system limitations that would suggest that additional SPS workers would cause significant impacts. Therefore, Dominion has concluded that impacts during the SPS license renewal term would be small.
  - Offsite land use – This issue addresses impacts that local government spending of plant property tax dollars can have on land use patterns. SPS property taxes are a large portion of the Surry County revenue and Dominion expects this to remain generally unchanged during the license renewal term. Land use patterns within the County, however, have not shown significant change since Dominion began making these payments. Based on past practices, Dominion concludes that impacts during the SPS license renewal term would be small.

- Public services; transportation – This issue addresses impacts that adding license renewal term workers could have on local traffic patterns. The primary access route to SPS carries a Commonwealth categorization (Level of Service = A) that indicates free flow of the traffic stream and that users are unaffected by the presence of others. NRC concluded, and Dominion concurs, that license renewal impacts in such cases would be small.
- Historic and archaeological resources – This issue address impacts that license renewal activities could have on resources of historic or archaeological significance. No such resources have been identified on the SPS site or associated transmission lines and Dominion has no plans for license renewal activities that would disturb unknown resources. Dominion consultation with the State Historic Preservation Officer has identified no issues of concern.

- Postulated accidents
  - Severe accidents – NRC determined that the license renewal impacts from severe accidents would be small, but determined that applicants should perform site-specific analyses of ways to further mitigate impacts. Dominion used NRC methodology to conduct a severe accident mitigation alternatives analysis and found one mitigation measure that might be cost-effective, but is unrelated to aging management or, therefore, to license renewal.

Findings

1. NRC has found that the environmental impacts of Category 1 issues are small. Dominion has adopted by reference NRC findings for Category 1 issues applicable to SPS.

2. For Category 2 issues applicable to SPS, Dominion has determined that the environmental impact is small.

3. To the best of Dominion's knowledge, SPS is in compliance with Virginia licensing and permitting requirements and is in compliance with its Commonwealth-issued licenses and permits.

4. Dominion's license renewal and continued operation of SPS would be consistent with the enforceable provisions of the Virginia coastal zone management program.

STATE NOTIFICATION

By this certification that SPS license renewal is consistent with Dominion's coastal zone management program, the Commonwealth of Virginia is notified that it has three months from receipt of this letter and accompanying information in which to concur or object with Virginia Power's certification. However, pursuant to 15 CFR 930.63(b), if the Commonwealth of Virginia has not issued a decision within three months following the commencement of state agency review, it shall notify the contacts listed below of the status of the matter and the basis for further delay. The Commonwealth's concurrence, objection, or notification of review status shall be sent to:

______________________________	Tony Banks
US Nuclear Regulatory Commission	Dominion
One White Flint North	Innsbrook Technical Center
11555 Rockville Pike	500 Dominion Blvd.
Rockville, MD. 20852-2738	Glen Allen Va. 23060

REFERENCES

1. *NRR Office Letter No. 906, Revision 2. "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues."* U. S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation. September 21, 1999.

2. *Virginia Coastal Resources Management Program Final Environmental Impact Statement*. U.S. Department of Commerce and Council on the Environment. Commonwealth of Virginia. July 1985. Reprinted April 1999.

3. *Enforceable Regulatory Programs comprising Virginia's Coastal Resources Management Program*. Commonwealth of Virginia. Department of Environmental Quality. Undated.

4. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. U.S Nuclear Regulatory Commission. May 1996.

FIGURE E-1

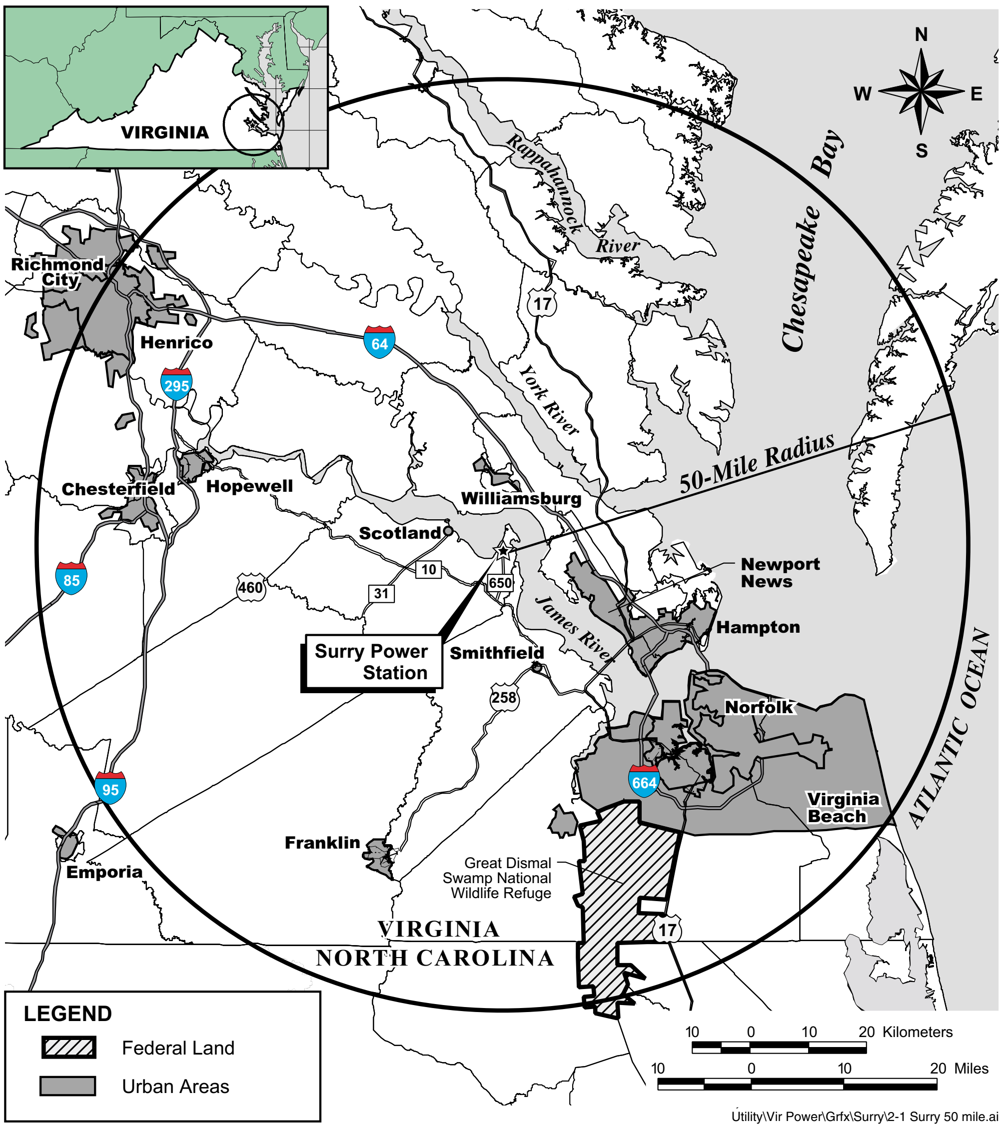

VIRGINIA
N
W
E
S
Richmond City
Henrico
Chesterfield
Hopewell
Williamsburg
Scotland
Surry Power Station
Smithfield
Newport News
Hampton
Norfolk
Virginia Beach
Franklin
Emporia
Great Dismal Swamp National Wildlife Refuge
Rappahannock River
York River
James River
Chesapeake Bay
ATLANTIC OCEAN
50-Mile Radius
VIRGINIA
NORTH CAROLINA
64
295
85
95
460
31
10
650
258
664
17
LEGEND
Federal Land
Urban Areas
10 0 10 20 Kilometers
10 0 10 20 Miles
Utility\Vir Power\Grfx\Surry\2-1 Surry 50 mile.ai

FIGURE E-2

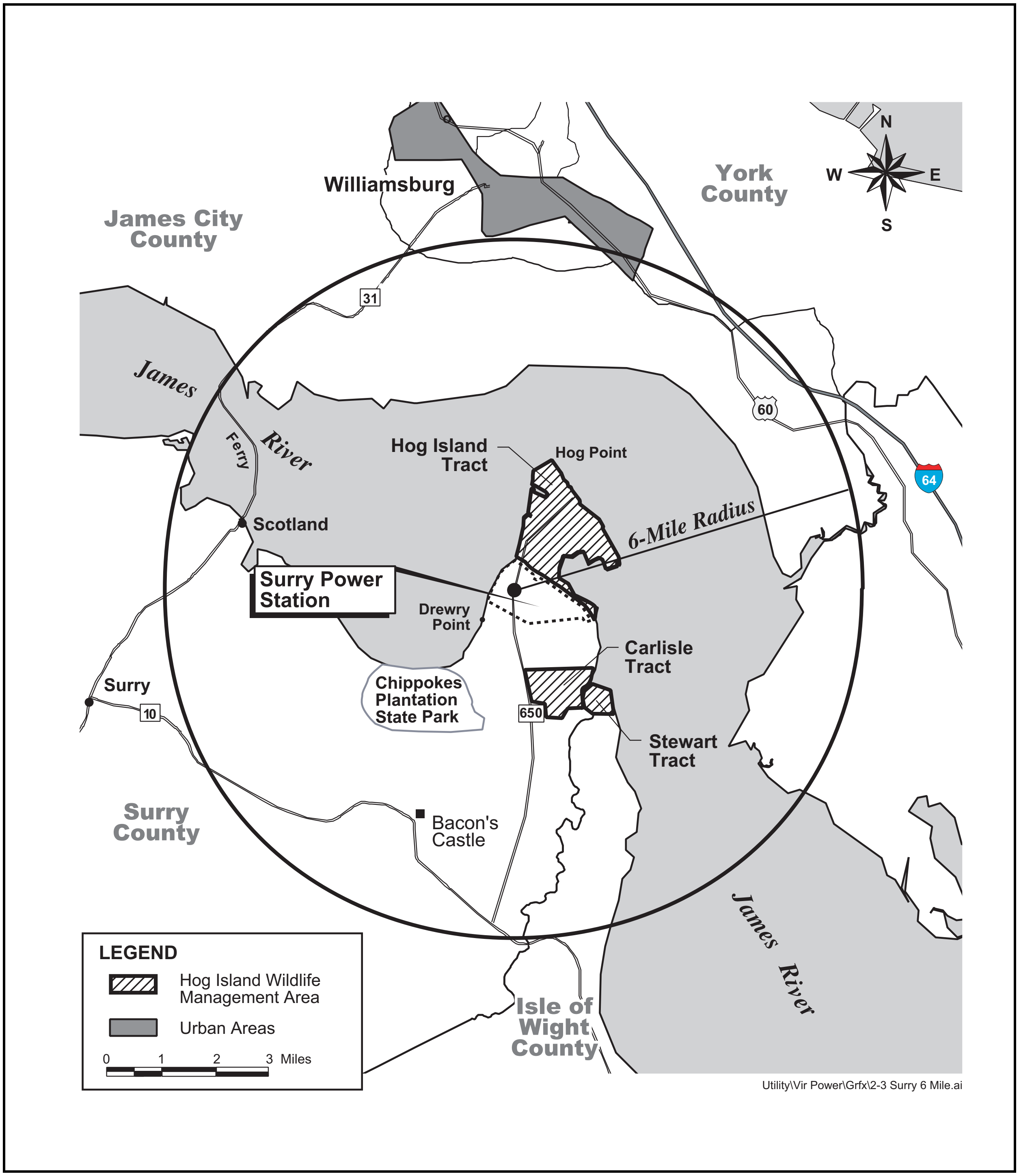

Williamsburg
James City County
York County
N
W
E
S
31
60
64
James River
Ferry
Hog Island Tract
Hog Point
6-Mile Radius
Scotland
Surry Power Station
Drewry Point
Carlisle Tract
Chippokes Plantation State Park
Surry
10
650
Stewart Tract
Surry County
Bacon's Castle
James River
Isle of Wight County
LEGEND
Hog Island Wildlife Management Area
Urban Areas
0 1 2 3 Miles
Utility\Vir Power\Grfx\2-3 Surry 6 Mile.ai

FIGURE E-3

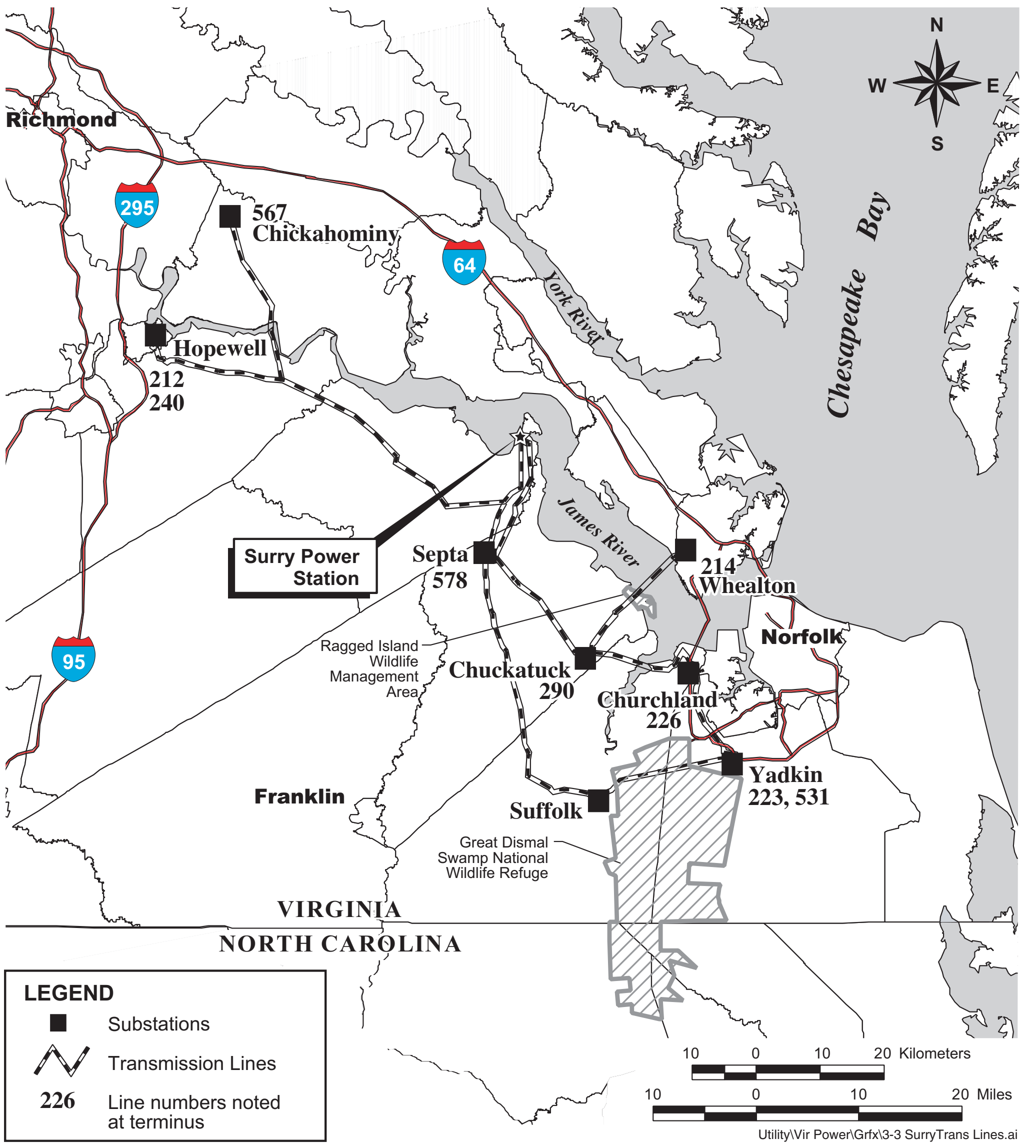

Richmond
295
567
Chickahominy
64
York River
Chesapeake Bay
N
W
E
S
Hopewell
212
240
James River
Surry Power Station
Septa
578
214
Whealton
Norfolk
95
Ragged Island Wildlife Management Area
Chuckatuck
290
Churchland
226
Yadkin
223, 531
Franklin
Suffolk
Great Dismal Swamp National Wildlife Refuge
VIRGINIA
NORTH CAROLINA
LEGEND
Substations
Transmission Lines
226
Line numbers noted at terminus
10 0 10 20 Kilometers
10 0 10 20 Miles
Utility\Vir Power\Grfx\3-3 SurryTrans Lines.ai

Table 3-1
Environmental Authorizations for Current SPS Operations

Agency	Authority	Requirement	Number	Issue Date or Expiration Date	Activity Covered
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.)	License to operate	DPR-32 (Unit 1); DPR-37 (Unit 2)	Expires on 05/25/12 (Unit 1); 01/29/13 (Unit 2)	Operation of Units 1 and 2
U.S. Fish and Wildlife Service	Migratory Bird Treaty Act (16 USC 703 – 712)	Permit	MB705136-0	Issued 01/01/01; Expires 12/31/00	Removal of up to 15 osprey nests causing safety hazards
U.S. Army Corps of Engineers	Federal Clean Water Act, Section 404 (33 USC 1344)	Authorization to use regional permit	97-RP-19, Project 99-V1336	Issued 08/27/99; Expires 08/12/03	Periodic maintenance dredging of the intake channel in the James River
U.S. Department of Transportation	49 CFR 107, Subpart G	Registration	053100002 0241	Issued 06/05/00 Expires 06/30/01	Hazardous materials shipments
VMRC	Cov Title 28.2, Chapters 12 and 13	Permit	VMRC 92-1347	Issued 08/02/99; Expires 12/31/02	Maintenance dredging of the intake channel in the James River

Table 3-1 (conditioned)
Environmental Authorizations for Current SPS Operations

Agency	Authority	Requirement	Number	Issue Date or Expiration Date	Activity Covered
VDEQ	9 VAC 25-610-40	Permit	GW0003900	Issued 08/01/99; Expires 08/01/09	Withdrawal of groundwater from wells for use as potable, process, and cooling water for SPS and Gravel Neck Combustion Turbines Station
Virginia Department of Health, Bureau of Water Supply Engineering	Section 3.14, Waterworks Regulations of the Virginia Department of Health	Permit	3181800	Issued 03/07/78; no expiration	Authorizes operation of a non-community waterworks
VDEQ	Federal Clean Water Act, Section 402 (33 USC 1342); Virginia State Water Control Law	Permit	VA0004090	Issued 09/23/96; Expires 09/23/01	Plant and stormwater discharges

Table 3-1 (conditioned)
Environmental Authorizations for Current SPS Operations

Agency	Authority	Requirement	Number	Issue Date or Expiration Date	Activity Covered
VDEQ	9 VAC 5-80-10	Permit	Letter, Williams (VDEQ) to Ahladas (VP), 09/27/93	Issued 09/27/93; No expiration date	Installation and operation of the emergency blackout generator
VDEQ	9 VAC 5-20-160	Registration	50336	Annual re-certification	Air emission sources
VDEQ	Federal Clean Air Act, Title V (42 USC 7661 et seq.); 9 VAC 5-80-10	Permit	None	Application submitted 01/12/98; Revised 04/07/98	Air emission source operation

APPENDIX F
MICROBIOLOGICAL ORGANISMS CORRESPONDENCE

Microbiological Organisms Correspondence is not applicable to Surry Power Station. This placeholder has been retained to maintain Table of Contents conformity with the North Anna Power Station Environmental Report, as an aid to regulatory review.

APPENDIX G
SEVERE ACCIDENT MITIGATION ALTERNATIVES ANALYSIS

TABLE OF CONTENTS

SECTION **PAGE**

LIST OF TABLES

SECTION **PAGE**

LIST OF FIGURES

SECTION **PAGE**

ACRONYMS USED IN APPENDIX G

AAC	Alternate Alternating Current
AC	Alternating Current
ADS	Automatic Depressurization System
AFW	Auxiliary Feedwater
AFWST	Auxiliary Feedwater Storage Tank
AMSAC	ATWS Mitigating System Actuation Circuitry
AOV	Air Operated Valve
ATWS	Anticipated Transient Without Scram
BWR	Boiling Water Reactor
BWST	Borated Water Storage Tank
CCW	Component Cooling Water
CDF	Core Damage Frequency
CE	Combustion Engineering
CRD	Control Rod Drive
CST	Condensate Storage Tank
CV	Control Valve
CVCS	Charging and Volume Control System
DC	Direct Current
DG	Diesel Generator
DHR	Decay Heat Removal
ECCS	Emergency Core Cooling System
EFIC	Emergency Feedwater Initiation and Control
EFW	Emergency Feedwater
EOP	Emergency Operating Procedure
ERCW	Emergency Raw Cooling Water
FW	Feedwater
HCLPF	High Confidence of Low Probability of Failure
HPCI	High Pressure Coolant Injection

HPCS	High Pressure Core Spray
HPI	High Pressure Injection
HPSI	High Pressure Safety Injection
HR	Heat Removal
HVAC	Heating, Ventilation and Air Conditioning
I&C	Instrumentation and Control
ICONE	International Conference on Nuclear Engineering
ICW	Intermediate Cooling Water
IPE	Individual Plant Examination
ISLOCA	Interfacing System LOCA
KV	Kilo-Volts
LOCA	Loss of Coolant Accident
LOP	Loss of Power
LOSW	Loss of Service Water
LPCI	Low Pressure Coolant Injection
LPI	Low Pressure Injection
LPSI	Low Pressure Safety Injection
MAB	Maximum Attainable Benefit
MCC	Motor Control Center
MD	Motor Driven
MFW	Main Feed Water
MG	Motor Generator
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
NRC	Nuclear Regulatory Commission
PMP	Probable Maximum Precipitation
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Analysis
PRT	Pressurizer Relief Tank
PSA	Probabilistic Safety Assessment

PWR	Pressurized Water Reactor
RAI	Request for Additional Information
RB	Reactor Building
RCIC	Reactor Core Isolation Cooling
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RV	Relief Valve
S/G	Steam Generator
SAMA	Severe Accident Mitigation Alternative
SAMDA	Severe Accident Mitigation Design Alternative
SAMG	Severe Accident Management Guideline
SBO	Station Blackout
SI	Safety Injection
SGTR	Steam Generator Tube Rupture
SLC	Standby Liquid Control
SOV	Solenoid Operated Valve
SPS	Surry Power Station
SRV	Safety Relief Valve
SSE	Safe Shutdown Earthquake
SW	Service Water
TD	Turbine Driven
TDP	Turbine Driven Pump
TVA	Tennessee Valley Authority
V	Volts
WBN	Watts Bar Nuclear Plant

G.1 MELCOR ACCIDENT CONSEQUENCES CODE SYSTEM MODELING

G.1.1 Introduction

The following sections describe the assumptions made and the results of modeling performed to assess the risks and consequences of severe accidents (U.S. Nuclear Regulatory Commission Class 9) at SPS.

The severe accident consequence analysis was carried out with the Melcor Accident Consequence Code System code (Ref. G.1-2). MACCS2 simulates the impact of severe accidents at nuclear power plants on the surrounding environment. The principal phenomena considered in MACCS2 are atmospheric transport, mitigating actions based on dose projection, dose accumulation by a number of pathways including food and water ingestion, early and latent health effects, and economic costs.

G.1.2 Input

The input data required by MACCS2 are outlined below. The Level 3 PRAs using the MACCS 2 computer code were prepared by Dominion and reviewed by Scientech and Dominion personnel, and are documented in Ref. G.1-11.

G.1.2.1 Core Inventory

The core inventory is for SPS at a power level of 2545 megawatts-thermal. These values were obtained by adjusting the end-of-cycle values for a 3,412 megawatt-thermal pressurized water reactor (Table G.1.1) by a linear scaling factor of 0.746 (Ref. G.1-2).

G.1.2.2 Source Terms

The source term input data to MACCS2 were the severe accident source terms presented in the probabilistic risk assessment in the SPS IPE (Ref. G.1-3). This document defines the releases in terms of release modes and demonstrates the method of calculating releases. There are 24 Plant Damage States (PDSs) which, when propagated through the containment event tree in Ref. G.1-3, lead to 25 source term categories. Table G.1-2 lists the conditional input release fractions for each MACCS2 nuclide group. The assignment of the radionuclides in Table G.1.1 to these nuclide groups is the same as that given in the standard MACCS2 input. Where other related source term data were not reported, such as release durations and energies, these were evaluated by comparison with similar releases reported in the NUREG-1150 studies for the Surry plant (Ref. G.1-4).

The amounts (becquerels) of each radionuclide released to the atmosphere for each accident sequence or release category are obtained by multiplying the (adjusted) core inventory at the time of the hypothetical accident (Table G.1.1) by the release fractions (Table G.1-2) assigned to each of the nuclide groups.

The offsite consequences are summed for all the release modes weighted by the annual frequency to obtain the total annual accident risk, for the base case and for each of the SAMA concepts evaluated. (This summation calculation is performed outside of the MACCS2 code as part of the SAMA cost-benefit analyses.)

G.1.2.3 Meteorological Data

The MACCS2 input used one year's (1998) hourly meteorological data for the plant for a base case. Two additional years' (1996-1997) hourly met data was used for sensitivity comparison. The hourly data (wind direction, wind speed, stability category, and precipitation) were collected on-site at the Surry Power Station met tower (Ref. G.1-5). The wind direction and wind speed were recorded at vent height (tower upper elevation); the stability data were determined by a Delta T system measuring the temperature at 10 meters and at vent height; and precipitation was measured at ground level. The instruments were calibrated quarterly. The data were temporarily stored at the sites in dataloggers which were polled nightly to transfer the data to a personal computer at Innsbrook. The data were quality controlled each business day by EP&C personnel. Professional meteorologists resolved any unusual data situations. Each month, the data were transferred to the corporate mainframe computer and were converted to and stored in SAS data sets. SAS programs were written to produce the hourly data files in MACCS2 format.

Morning and afternoon mixing height values for 1996 through 1998 were obtained from the National Climatic Data Center. Missing values were replaced where possible as prescribed in the USEPA document "Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models." All non-missing values greater than zero were considered valid.

MACCS2 calculations examine a representative subset of the 8,760 hourly observations in 1998 contained in one year’s data set (typically about 150 sequences). The representative subset is selected by sampling the weather sequences after sorting them into weather bins defined by wind speed, atmospheric stability, and rain conditions at various distances from the site.

G.1.2.4 **Population Distribution**

The population distribution and land use information for the region surrounding the site are specified in the Site Data File. Contained in the Site Data file are the geometry data used for the site (spatial intervals and wind directions), population distribution, fraction of the area that is land, watershed data for the liquid pathways model, information on agricultural land use and growing seasons, and regional economic information. Some of the detailed data in this file supercedes certain data in the EARLY input file.

Much of the data was initially prepared by the computer program SECPOP90 [Ref. G.1-6]. This code contains a database extracted from Bureau of the Census PL 94-171 (block level census) CD-ROMS [Ref. G.1-7], the 1992 Census of Agriculture CD ROM Series 1B, the 1994 US Census County and City Data Book CD-ROM, the 1993 and 1994 Statistical Abstract of the United States, and other minor sources. The reference contains details on how its database was created and checked. The output from SECPOP90 is a file in the MACCS2 site file format based on the data in its reference data base for the specified site.

The plant location for SPS Unit 1 is Latitude 37º 9’ 59’’N and Longitude 76º 41’ 55’’W as listed in the Surry UFSAR Section 2.2.1. The 50 mile radius area around the plant was divided into sixteen directions that are equivalent to a standard navigational compass rosette. This rosette was further divided into 10 "inner" radial rings, each with sixteen azimuthal sections. A picture of the rosette for Surry 50 mile radius is shown in Figure G.1-1.

The SECPOP90-prepared data was then modified and updated using the SPS UFSAR (Ref. G.1-8) Section 2.1 50 mile population distribution for the year 2030 in place of the 1990 Census SECPOP90 data.

G.1.2.5 **Emergency Response**

The EARLY module of the MACCS code models the time period immediately following a radioactive release. This transient period is commonly referred to as the emergency phase. It may extend up to 1 week after the arrival of the first plume at any downwind spatial interval. The subsequent intermediate and long term periods are treated by CHRONC. In the EARLY module the user may specify emergency response scenarios that include evacuation, sheltering, and dose-dependent relocation. The EARLY module has the capability for combining results from up to three different emergency response scenarios. This is accomplished by appending change records to the EARLY input file. The first emergency-response scenario is defined in the main body of the EARLY input file.

Up to two additional emergency-response scenarios can be defined through change record sets positioned at the end of the file.

The emergency evacuation model has been modeled as a single evacuation zone extending out 10 miles from the plant. The average evacuation speed is estimated (see Table G.2-1 of Ref. G.1-4) to be on the order of 4 mph (1.8 m/s). For the purposes of this analysis an average evacuation speed of 1.8 m/s is used with a 7200 second delay between the alarm and start of evacuation, with no sheltering for the base case.

To demonstrate the possible significance of these assumptions, a sensitivity MACCS2 run was made with the alarm times and the delay times arbitrarily reduced by 0.5 hours (-1800 s). The results, which are reported in Section G.2.4, demonstrate that the MACCS2 consequences are not significantly sensitive to the timings used.

G.1.2.6 **Economic Data**

Land use statistics including farmland values, farm product values, dairy production, and growing season information were provided on a countywide basis within 50 miles.

Much of the data is prepared by the computer program SECPOP90 (Ref. G.1-6). It contains a database extracted from Bureau of the Census PL 94-171 (block level census) CD-ROMS (Ref. G.1-7), the 1992 Census of Agriculture CD ROM Series 1B, the 1994 US Census County and City Data Book CD-ROM, the 1993 and 1994 Statistical Abstract of the United States, and other minor sources. The reference contains details on how the database was created and checked. The SECPOP90 regional economic values were updated to 1999 using cost of living and other data from the Bureau of the Census and the Department of Agriculture. Agricultural data is taken from data available in the 1999 Census of Agriculture (Ref. G.1-9). This was accomplished by replacing the SECPOP90 data for the counties within the fifty mile radius by the 1999 value. That is, the SECPOP90 county data base was modified so that the results produced by the code were correctly assigned to the various economic regions.

Economic consequences were estimated by summing the following costs:

- Costs of evacuation,
- Costs for temporary relocation (food, lodging, lost income),
- Costs of decontaminating land and buildings,
- Lost return-on-investments from properties that are temporarily interdicted to allow contamination to be decreased by decay of nuclides,
- Costs of repairing temporarily interdicted property,
- Value of crops destroyed or not grown because they were contaminated by direct deposition or would be contaminated by root uptake, and
- Value of farmland and of individual, public, and nonfarm commercial property that is condemned.

Costs associated with damage to the reactor, the purchase of replacement power, medical care, life-shortening, and litigation are not calculated by MACCS2.

G.1.3 **Results**

Based on the preceding input data, MACCS2 was used to estimate the following:

- The downwind transport, dispersion, and deposition of the radioactive materials released to the atmosphere from the failed reactor containment.
- The short- and long-term radiation doses received by exposed populations via direct (cloudshine, plume inhalation, groundshine, and resuspension inhalation) and indirect (ingestion) pathways.
- The mitigation of those doses by protective actions (evacuation, sheltering, and post-accident relocation of people; disposal of milk, meat, and crops; and decontamination, temporary interdiction, or condemnation of land and buildings).
- The early fatalities and injuries expected to occur within 1 year of the accident (early health effects) and the delayed (latent) cancer fatalities and injuries expected to occur over the lifetime of the exposed individuals.
- The offsite costs of short-term emergency response actions (evacuation, sheltering, and relocation), of crop and milk disposal, and of the decontamination, temporary interdiction, or condemnation of land and buildings.

The consequences calculated with the MACCS2 model in terms of the population dose and offsite economic costs for the SAMA base case and two sensitivity cases are shown in Table G.1-3.

Table G.1.1
SPS Core Inventory[a]

Nuclide	Core inventory (becquerels)	Nuclide	Core inventory (becquerels)
Cobalt-58	3.22E+16	Tellurium-131M	4.68E+17
Cobalt-60	2.47E+16	Tellurium-132	4.66E+18
Krypton-85	2.48E+16	Iodine-131	3.21E+18
Krypton-85M	1.16E+18	Iodine-132	4.73E+18
Krypton-87	2.12E+18	Iodine-133	6.78E+18
Krypton-88	2.86E+18	Iodine-134	7.44E+18
Rubidium-86	1.89E+15	Iodine-135	6.39E+18
Strontium-89	3.59E+18	Xenon-133	6.78E+18
Strontium-90	1.94E+17	Xenon-135	1.27E+18
Strontium-91	4.62E+18	Cesium-134	4.32E+17
Strontium-92	4.80E+18	Cesium-136	1.32E+17
Yttrium-90	2.08E+17	Cesium-137	2.42E+17
Yttrium-91	4.37E+18	Barium-139	6.28E+18
Yttrium-92	4.82E+18	Barium-140	6.22E+18
Yttrium-93	5.45E+18	Lanthanum-140	6.35E+18
Zirconium-95	5.53E+18	Lanthanum-141	5.83E+18
Zirconium-97	5.76E+18	Lanthanum-142	5.62E+18
Niobium-95	5.22E+18	Cerium-141	5.65E+18
Molybdium-99	6.10E+18	Cerium-143	5.49E+18
Technetium-99M	5.26E+18	Cerium-144	3.41E+18
Ruthenium-103	4.54E+18	Praseodymium-143	5.40E+18
Ruthenium-105	2.95E+18	Neodymium-147	2.41E+18
Ruthenium-106	1.03E+18	Neptunium-239	6.46E+19
Rhodium-105	2.05E+18	Plutonium-238	3.66E+15
Antimony-127	2.79E+17	Plutonium-239	8.26E+14
Antimony-129	9.87E+17	Plutonium-240	1.04E+15
Tellurium-127	2.69E+17	Plutonium-241	1.76E+17
Tellurium-127M	3.56E+16	Americium-241	1.16E+14
Tellurium-129	9.27E+17	Curium-242	4.44E+16
Tellurium-129M	2.44E+17	Curium-244	2.60E+15

a. Ref. G.1-2.

Table G.1-2
SPS Release Fraction By Nuclide Group

Source Term Category	Noble Gases	I	Cs	Te	Sr	Ru	La	Ce	Ba
2	7.20E-02	8.60E-07	8.60E-07	0.0	0.0	5.40E-06	0.0	3.30E-07	0.0
5	6.10E-01	7.80E-03	6.90E-03	1.50E-03	6.50E-04	2.60E-03	2.60E-03	1.50E-05	5.30E-04
7	9.00E-01	7.40E-02	9.70E-02	1.80E-02	1.50E-02	2.50E-02	8.10E-06	2.40E-07	8.70E-03
*8 (1)	7.80E-01	4.10E-02	6.00E-02	5.00E-03	6.00E-05	1.50E-02	1.50E-05	2.20E-06	3.70E-03
(2)	1.60E-01	6.70E-02	9.70E-02	1.40E-02	1.70E-02	2.40E-03	5.30E-06	1.00E-07	6.10E-03
11	8.20E-01	2.30E-06	1.40E-05	1.80E-05	3.20E-04	3.90E-04	0.0	0.0	1.30E-05
13	9.80E-01	4.60E-03	3.20E-03	2.00E-05	0.0	0.0	0.0	0.0	2.60E-06
15	9.00E-01	1.10E-04	3.40E-04	1.00E-04	3.20E-04	4.10E-04	0.0	0.0	9.20E-05
18	8.50E-01	3.30E-03	3.30E-03	3.80E-04	2.20E-03	2.50E-03	1.20E-06	0.0	6.00E-04
21	6.80E-04	7.60E-05	7.60E-05	0.0	2.70E-07	2.90E-07	0.0	0.0	0.0
22	9.40E-01	5.10E-02	5.40E-02	2.70E-03	4.10E-02	5.10E-02	6.40E-05	0.0	9.60E-02
23	9.40E-01	2.90E-01	3.10E-01	1.50E-02	2.30E-01	2.80E-01	3.60E-04	4.60E-07	5.40E-01
24	1.00E-00	5.20E-01	5.40E-01	2.40E-02	3.40E-02	1.40E-01	5.50E-05	1.10E-05	2.10E-02

* STC-8 is divided into 2 plumes

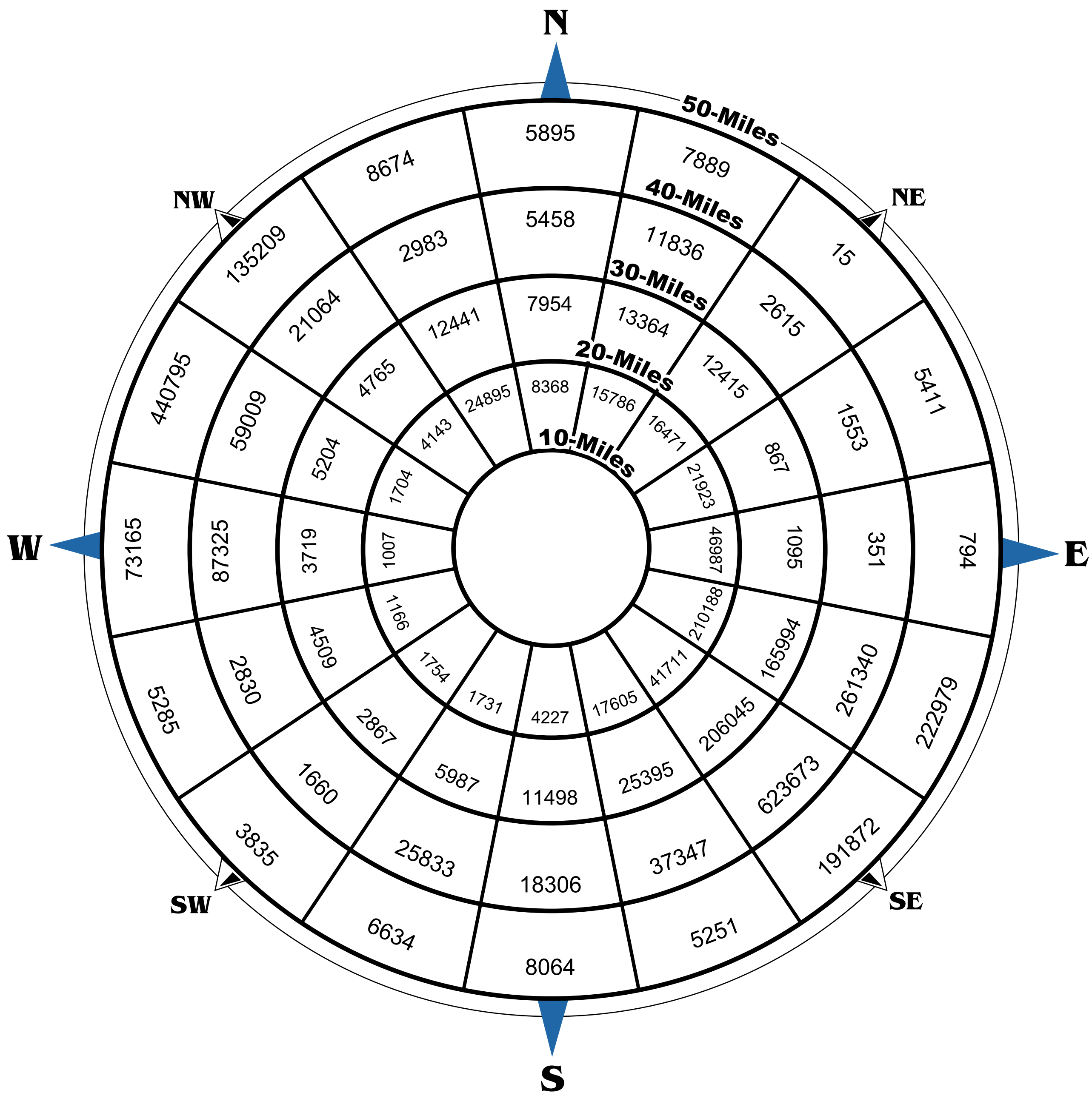
STCs 1 and 20 have a release fraction of 0.0 for all radionuclides.
STCs 3, 10 and 12 are assigned the release fractions for STC 5.
STCs 4, 6 and 19 are assigned the release fractions for STC 8.
STCs 9, 16 are assigned the release fractions for STC 11.
STC 14 is assigned the release fractions for STC 15.
STC 17 is assigned the release fractions for STC 2.

Table G.1-3
Summary of Offsite Consequence Results for Each Release Mode

	Population Dose (Sieverts)			Offsite Economic Costs (Dollars)		
CET End Point (Release Mode)	Basecase (100% Evac)	95% Evac	-50% Timing	Basecase (100% Evac)	95% Evac	-50% Timing
STC-2	5.98E+00	6.02E+00	6.05E+00	7.73E+06	6.68E+01	9.31E+06
STC-5	8.23E+03	8.28E+03	7.60E+03	7.34E+08	7.50E+08	8.32E+08
STC-7	2.59E+04	2.62E+04	2.80E+04	5.58E+09	5.77E+09	5.37E+09
STC-8	1.74E+04	1.76E+04	1.72E+04	3.38E+09	3.48E+09	3.44E+09
STC-11	2.50E+02	2.51E+02	2.64E+02	6.23E+06	3.19E+05	5.63E+06
STC-13	2.89E+03	2.90E+03	2.87E+03	1.60E+08	1.59E+08	1.71E+08
STC-15	7.10E+02	7.12E+02	7.45E+02	9.34E+06	3.54E+06	8.30E+06
STC-18	4.71E+03	4.72E+03	4.44E+03	3.32E+08	3.35E+08	2.87E+08
STC-21	1.19E+02	1.19E+02	1.23E+02	9.40E+06	9.53E+04	8.93E+06
STC-22	2.75E+04	2.81E+04	2.80E+04	4.85E+09	5.01E+09	5.08E+09
STC-23	6.81E+04	7.00E+04	6.94E+04	1.22E+10	1.26E+10	1.27E+10
STC-24	5.07E+04	5.18E+04	4.59E+04	1.27E+10	1.31E+10	1.12E+10

STCs 3, 10 and 12 are assigned the release fractions for STC 5.
STCs 4, 6 and 19 are assigned the release fractions for STC 8.
STCs 9, 16 are assigned the release fractions for STC 11.
STC 14 is assigned the release fractions for STC 15.
STC 17 is assigned the release fractions for STC 2.

Figure G.1-1
Population Distribution Within 50 Miles



POPULATION BY ANNULUS

ANNULUS	0 TO 10	10 TO 20	20 TO 30	30 TO 40	40 TO 50	TOTAL
POPULATION	176,308	419,666	484,117	1,163,183	1,121,767	3,365,040

G.1.4 **References**

Ref. G.1-2 Code Manual for MACCS2: Volume 1, User's Guide, Chanin, D. I., et al, SAND07-054, March 1997. see also:

MACCS2 V.1.12, CCC-652 Code Package, ORNL (Oak Ridge National Laboratory RISCC Computer Code Collection), 1997.

MELCOR Accident Consequence Code System (MACCS) Model Description, Jow, H. N, et al, NUREG/CR-4691, SAND86-1562, February 1990.

Ref. G.1-3 Surry Power Station IPE, Virginia Electric And Power Company, August 1991.

Ref. G.1-4 Evaluation of Severe Accident Risks: Surry 1 Main Report, NUREG/CR-4551, Vol. 3, Rev. 1, Part 1, Breeding, R. J., et al, October 1990.

Ref. G.1-5 RF-Memo, Philip C. Knause, "Nuclear Relicensing Meteorological Data Documentation", December 29, 1999. (See Appendix II).

Ref. G.1-6 RF-Report, S. L. Humphreys, et al., "SECPOP90: Sector Population, Land Fraction, and Economic Estimation Program, " NUREG/CR-6525, September, 1997.

Ref. G.1-7 RF-Report, Bureau of the Census, "Census of Population and Housing, 1990: Public Law (P. L.) 94-171, Data Technical Documentation", CD- ROM set, 1991.

Ref. G.1-8 Surry Power Station UFSAR.

Ref. G.1-9 RF-Report, U.S. Dept. of Agriculture, "1997 Census of Agriculture," National Agricultural Statistics Service.

Ref. G.1-10 Evaluation of Severe Accident Risks: Quantification of Major Input Parameters MACCS Input, NUREG/CR 4557, Vol. 2, Rev. 1., Part 7, Sprung, J. L. et al, December 1990.

Ref. G.1-11 RF-CALC, Dominion/Virginia Power Calculation SM-1242, Rev. 0, "MACCS2 Model For North Anna Level 3 Application."

G.2 EVALUATION OF CANDIDATE SAMAs

This section describes the generation of the initial list of potential SAMAs for SPS, screening methods and the analysis of the remaining SAMAs.

G.2.1 SAMA List Compilation

Dominion generated a list of candidate SAMAs by reviewing industry documents and considering plant-specific enhancements not considered in published industry documents. Industry documents reviewed include the following:

- The SPS IPE submittal (only items not already evaluated and/or implemented during the IPE) (Ref. G.2-1)
- The Watts Bar Nuclear Plant Unit 1 PRA/IPE submittal (Ref. G.2-2)
- The Limerick SAMDA cost estimate report (Ref. G.2-3)
- NUREG-1437 description of Limerick SAMDA (Ref. G.2-4)
- NUREG-1437 description of Comanche Peak SAMDA (Ref. G.2-5)
- Watts Bar SAMDA submittal (Ref. G.2-6)
- TVA response to NRC's RAI on the Watts Bar SAMDA submittal (Ref. G.2-7)
- Westinghouse AP600 SAMDA (Ref. G.2-8)
- Safety Assessment Consulting (SAC) presentation by Wolfgang Werner at the NUREG-1560 conference (Ref. G.2-9)
- NRC IPE Workshop - NUREG-1560 NRC Presentation (Ref. G.2-10)
- NUREG-0498, supplement 1, Section 7 (Ref. G.2-11)
- NUREG/CR-5567, PWR Dry Containment Issue Characterization (Ref. G.2-12)
- NUREG-1560, Volume 2, NRC Perspectives on the IPE Program (Ref. G.2-13)
- NUREG/CR-5630, PWR Dry Containment Parametric Studies (Ref. G.2-14)
- NUREG/CR-5575, Quantitative Analysis of Potential Performance Improvements for the Dry PWR Containment (Ref. G.2-15)
- CE System 80+ Submittal (Ref. G.2-16)
- NUREG-1462, NRC Review of ABB/CE System 80+ Submittal (Ref. G.2-17)
- An ICONE paper by C. W. Forsberg, et. al, on a core melt source reduction system (Ref. G.2-18)
- The SPS IPEEE submittal (only items not already evaluated and/or implemented during the IPEEE) (Ref. G.2-19)
- Additional items from the SPS PRA staff or from the review of the top 100 cutsets

Although SPS is a Westinghouse design, each of the above documents were reviewed for potential SAMAs even if they were not necessary applicable to a Westinghouse plant. Those items not applicable to SPS were subsequently screened from this list. The containment performance improvement programs for boiling water reactors and ice condenser plants were not reviewed (and the NUREG-1560 portion of the containment performance improvement for these were not reviewed). Conceptual enhancement for which no specific details were available (e.g., "improve diesel reliability" or "improve procedures for loss of support systems") were not included, unless they were considered as vulnerabilities in the SPS IPE.

G.2.2 Qualitative Screening of SAMAs

The initial list of 160 potential SAMAs are presented in Table G.2-1. Table G.2-1 also presents a qualitative screening of the initial list. Items were eliminated from further evaluation based on one of the following criteria:

- The SAMA is not applicable at SPS, either because the enhancement is only for boiling water reactors, the Westinghouse AP600 design or PWR ice condenser containments, or it is a plant specific enhancement that does not apply at SPS (Criterion A – Not applicable); or
- The SAMA has already been implemented at SPS (or the SPS design meets the intent of the SAMA) (Criterion B – Implemented or intent met).
- The SAMA is related to a Reactor Coolant pump (RCP) seal vulnerability at many PWRs stemming from charging pump dependency on Component Cooling Water (CCW). The SPS does not have this vulnerability because the charging pumps do not rely on CCW. However, other RCP seal LOCA improvements will still be considered (Criterion C).

Based on preliminary screening, 107 improvements were either eliminated or combined with other potential improvements, leaving 53 subject to the final screening process. These improvements are listed in Table G.2-2.

The final screening process involved identifying and eliminating those items whose cost exceeded their benefit. Table G.2-2 provides a description of the evaluation of each and provides the basis for their elimination or describes their final resolution. In general, the conclusion of each quantitative analysis resulted in a cost that exceeded the benefit by at least a factor of two. The presentation of the factor of two in Table G.2-2 was arbitrary, but provided confidence that even when uncertainties are considered, the cost would still exceed the benefit.

G.2.3 Analysis of Potential SAMAs

The quantitative analysis of the SAMAs was performed using the North Anna Probabilistic Risk Assessment (PRA). The PRA model used for the SAMA analysis consists of the usual three elements: The level I model looks at accident scenarios from initiation to the point of a plant damage state (core damage with containment heat removal status). The level II model assesses the likelihood that the plant damage state will result in each of the release categories. Finally, the level III model considers the distribution of the released radionuclides to the environment.

The level I model was originally developed in response to the request for information contained in Generic Letter 88-20. The fault tree linking approach was used and all event trees and fault trees were developed based on plant drawings and procedures. The model includes detailed fault tree models of all front line (accident mitigating) systems and their support systems (HVAC, Electrical, Air). The model also included detailed event trees which delineate accident sequences based primarily on the temporal response of the systems needed to mitigate the initiating event. The model was completed in August 1991. A minor update of the models was performed to support the IPEEE fire analysis which was completed in December 1994. The last major update was in 1997 as part of an upgrade to support implementation of the maintenance rule. At this time several more support system models were updated. The three year plant specific unavailability developed for the maintenance rule program was also used to update the maintenance unavailability basic events.

A full level II model was developed for the IPE and completed at the same time as the level I model. The level II model consists of a containment event tree with nodes that represent phenomenological events. The nodes were quantified using subordinate trees and logic rules. The original level II model was updated slightly for the SAMA analysis. Recent experimental results have shown that certain outcomes on the containment event tree are much less likely than previously thought. These changes were incorporated into the level II model.

The level III model was constructed for the SAMA analysis under the leadership of SCIENTECH. The meteorological data have been collected by the Dominion meteorology department. Population data were determined based on software purchased from the federal government (SEGPOP). The MACCS2 code was used to do the evaluation of the source term distribution.

The information used in the level I model was verified using plant walkdowns. An independent peer review was conducted of the level I and level II models prior to submittal to

NRC. The level I model used for the SAMA analysis was also reviewed as the pilot plant for the Westinghouse Owners Group (WOG) PRA certification project.

The methodology used for this evaluation was based upon the NRC's guidance for the performance of cost-benefit analyses (Ref. G.2-20). This guidance involves determining the net value for each SAMA according to the following formula:

Net Value = (APE + AOC + AOE + AOSC) – COE

where:

APE	=	present value ($) of averted public exposure from the results of the MACCS2 model,
AOC	=	present value ($) of averted offsite property damage costs from the results of the MACCS2 model,
AOE	=	present value ($) of averted occupational exposure from the guidance provided Ref. G.2-20,
AOSC	=	present value ($) of averted onsite costs including cleanup/ decontamination costs, repair/refurbishment costs, replacement power costs,
COE	=	cost of enhancement ($).

If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA and is not considered beneficial. The derivation of each of these costs is described in below.

The following specific values were used for various terms in the analyses:

Present Worth

The present worth was determined by:

$$P = \frac{1 - e^{-rt}}{r}$$

Where:

r is the discount rate = 7% (assumed throughout these analyses)

t is the duration of the license renewal = 20 years

PW is the present worth of a string of annual payments = 10.76

Dollars per REM

The conversion factor used for assigning a monetary value to on-site and off-site exposures was $2,000/person-rem averted. This is consistent with the NRC's regulatory analysis guidelines presented in and used throughout NUREG/BR-0184, Ref. G.2-20.

On-site Person REM per Accident

The occupational exposure associated with severe accidents was assumed to be 23,300 person-rem/accident. This value includes a short-term component of 3,300 person-rem/accident and a long-term component of 20,000 person-rem/accident. These values are the "best estimate" values provided in Section 5.7.3 of Ref. G.2-20. In the cost-benefit analyses, the accident-related on-site exposures were calculated using the best estimate exposure components applied over the on-site cleanup period.

On-site Cleanup Period

In the cost-benefit analyses, the accident-related on-site exposures were calculated over a 10-year cleanup period.

Present Worth On-site Cleanup Cost per Accident

The estimated cleanup cost for severe accidents was assumed to be $1.5E+09/accident (undiscounted). This value was derived by the NRC in Ref. G.2-20, Section 5.7.6.1, Cleanup and Decontamination. This cost is the sum of equal annual costs over a 10-year cleanup period. At a 7% discount rate, the present value of this stream of costs is $1.1E+09.

Methods for Calculating Averted Costs Associated with Onsite Accident Dose and Property Loss Costs

a) **Immediate Doses** (at time of accident and for immediate management of emergency)

For the case where the plant is in operation, the equations in Ref. G.2-20 can be expressed as:

$$W_{LTO} = (F_S D_{LTO_S} - F_A D_{LTOA}) R \frac{1 - e^{-rt_g}}{r} \qquad (1)$$

where:

W_{IO} = monetary value of accident risk avoided due to immediate doses, after discounting

R = monetary equivalent of unit dose, ($/person-rem)

F = accident frequency (events/yr)

D_{IO} = immediate occupational dose (person-rems/event)

S = status quo (current conditions)

A = after implementation of proposed action

r = real discount rate

t_f = years remaining until end of facility life.

The values used are:

R = $2000/person rem

r = .07

D_{LTO} = 3,300 person-rems /accident (best estimate)

The license extension time of 20 years is used for t_f.

For the basis discount rate, assuming F_A is zero, the best estimate of the limiting saving is

$$W_{IO} = \left(F_S D_{LTO_S}\right) R \frac{1 - e^{-rt_f}}{r}$$

$$= 3300 * F * \$2000 * \frac{1 - e^{-.07*20}}{.07}$$

$$= F * \$6{,}600{,}000 * 10.763$$

$$= F * \$0.71E{+}8, (\$).$$

b) **Long-Term Doses** (process of cleanup and refurbishment or decontamination)

For the case where the plant is in operation, the equations in Ref. G.2-20 can be expressed as:

$$W_{LTO} = (F_S D_{LTO} - F_A D_{LTO_A}) R * \frac{1 - e^{-rt_f}}{r} * \frac{1 - e^{-rm}}{rm} \qquad (2)$$

where:

W_{IO} = monetary value of accident risk avoided long term doses, after discounting, $

m = years over which long-term doses accrue.

The values used are:

R = \$2000/person rem

r = .07

D_{LTO} = 20,000 person-rem /accident (best estimate)

m = "as long as 10 years"

The license extension period of 20 years is used for t_f.

For the discount rate of 7%, assuming FA is zero, the best estimate of the limiting saving is

$$W_{LTO} = (F_S D_{LTO_S}) R * \frac{1 - e^{-rt_f}}{r} * \frac{1 - e^{-rm}}{rm}$$

$$= (F_S\ 20{,}000)\ \$2000 * \frac{1 - e^{-.07*20}}{.07} * \frac{1 - e^{-.07*10}}{.07 * 10}$$

$$= F_S * \$40{,}000{,}000 * 10.763 * 0.719$$

$$= F_S * \$3.18E + 8, \$$$

c) **Total Accident-Related Occupational (On-site) Exposures**

Combining equations (1) and (2) above, using delta (D) to signify the difference in accident frequency resulting from the proposed actions, and using the above numerical values, the long term accident related on-site (occupational) exposure avoided (AOE) is:

Best Estimate:

$$AOE = \Delta W_{IO} + \Delta W_{LTO} = \Delta F * \$(0.71 + 3.1)E + 8 = \Delta F * 3.81E + 8\ (\$)$$

where the Δ represents the change from the base case.

Methods Calculation of Averted Costs Associated with Accident-Related On-Site Property Damage

a) **Cleanup/Decontamination**

Ref. G.2-20 assumes a total cleanup/decontamination cost of \$1.5E+9 as a reasonable estimate and this same value was adopted for these analyses. Considering a 10-year cleanup period, the present value of this cost is:

$$PV_{CD} = \left(\frac{C_{CD}}{m}\right)\left(\frac{1 - e^{-rm}}{r}\right)$$

Where

PV_{CD} = Present value of the cost of cleanup/decontamination.

C_{CD} = Total cost of the cleanup/decontamination effort.

m = Cleanup period.

r = Discount rate.

Based upon the values previously assumed:

$$PV_{CD} = \left(\frac{\$1.5E+9}{10}\right)\left(\frac{1-e^{-.07*10}}{.07}\right)$$

$$PV_{CD} = \$1.079E+9$$

This cost is integrated over the term of the proposed license extension as follows

$$U_{CD} = PV_{CD}\frac{1-e^{-rt}}{r}$$

Based upon the values previously assumed:

$$U_{CD} = \$1.079E{+}9[10.763]$$

$$U_{CD} = \$1.161E{+}10$$

b) **Replacement Power Costs**

Replacement power costs, U_{RP} are an additional contributor to onsite costs. These are calculated in accordance with NUREG/BR-0184, Section 5.6.7.2.[1] Since replacement power will be needed for that time period following a severe accident, for the remainder of the expected generating plant life, long-term power replacement calculations have been

1. The section number for Section 5.6.7.2 apparently contains a typographical error. This section is a subsection of 5.7.6 and follows 5.7.6.1. However, the section number as it appears in the NUREG will be used in this document.

used. For a "generic" plant of 910 MWe, the present value of replacement power is calculated as follows:

$$PV_{RP} = \left(\frac{1.2E + 8}{r}\right)(1 - e^{-rt_f})^2$$

Where

PV_{RP} = Present value of the cost of replacement power for a single event.

t_f = years remaining until end of facility life.

r = Discount rate.

The $1.2E+8 value has no intrinsic meaning but is a substitute for a string of non-constant replacement power costs that occur over the lifetime of a "generic" reactor after an event (from Ref. G.2-20). This equation was developed per NUREG/BR-0184 for discount rates between 5% and 10% only.

For discount rates between 1% and 5%, Ref. G.2-20 indicates that a linear interpolation is appropriate between present values of $1.2E+9 at 5% and $1.6E+9 at 1%. So for discount rates in this range the following equation was used to perform this linear interpolation.

$$PV_{RP} = (\$1.6E + 9) - \left(\frac{[(\$1.6E+ 9) - (\$1.2E + 9)]}{[5\% - 1\%]} * [r_s - 1\%]\right)$$

Where

rs = Discount rate (small), between 1% and 5%.

To account for the entire lifetime of the facility, U_{RP} was then calculated from PVRP, as follows:

$$U_{RP} = \frac{PV_{RP}}{r}(1 - e^{-rt_f})^2$$

Where

U_{RP} = Present value of the cost of replacement power over the life of the facility.

Again, this equation is only applicable in the range of discount rates from 5% to 10%. NUREG/BR-0184 states the for lower discount rates, linear interpolations for U_{RP} are recommended between \$1.9E+10 at 1% and \$1.2E+10 at 5%. The following equation was used to perform this linear interpolations:

$$U_{RP} = (\$1.9E + 10) - \left(\frac{[(\$1.9E + 10) - (\$1.2E + 10)]}{[5\% - 1\%]} * [r_s - 1\%]\right)$$

Where

rs = Discount rate (small), between 1% and 5%.

The SPS has a gross electrical output of 855.4 MWe and a net of 801 MWe, compared to the "generic" plant of 910 MWe. Therefore, the replacement power cost formulae could be reduced by a factor of 0.94, but the generic formulae will be conservatively used.

c) **<u>Repair and Refurbishment</u>**

It is assumed that the plant would not be repaired.

d) **<u>Total Onsite Property Damage Costs</u>**

The total averted onsite damage costs is, therefore:

$$AOSC = F*(U_{CD} + U_{RP})$$

Where F = Annual frequency of the event.

<u>Accident-Related Off-Site Dose Costs</u>

Offsite doses were determined using the MACCS2 model developed for SPS. Costs associated with these doses were calculated using the following equation:

$$APE = (F_S D_{P_S} - F_A D_{P_A}) R \frac{1 - e^{-rt_f}}{r} \qquad (1)$$

where:

APE = monetary value of accident risk avoided due to population doses, after discounting

R = monetary equivalent of unit dose, (\$/person-rem)

F = accident frequency (events/yr)

D_P = population dose factor (person-rems/event)

S = status quo (current conditions)

A = after implementation of proposed action

r = real discount rate

t_f = years remaining until end of facility life.

Using the values for r, t_f, and R given above:

$$W_P = (\$2.15E+4)(F_S D_{P_S} - F_A D_{P_A})$$

Accident-Related Off-Site Property Damage Costs

$$AOC = (F_S P_{D_S} - F_A P_{D_A})\frac{1-e^{-rt_f}}{r}$$

AOC = monetary value of accident risk avoided due to offsite property damage, after discounting

PD = offsite property loss factor (dollars/event)

The evaluation process described in Ref. G.2-20 calculates the value of averted risk on an annual basis. Therefore, a method of "discounting" is used to calculate the "present value" or "present worth of averted risk" based on a specified period of time. For this analysis, a discount factor of 7% as described in the NRC Regulatory Analysis Technical Evaluation Handbook was used to determine the present worth of averted risk over the 20 year license renewal period for SPS.

The PSA results used in this analysis are calculated using internal event results only. To account for the potential impact of external events on the results of these SAMA evaluations, since SPS does not currently have an external events model that can be easily quantified, it was assumed that the benefits of each SAMA would be doubled for purposes of comparing with its cost. However, for some SAMAs that relate only to specific internal events initiators (e.g., some SGTR and ISLOCA SAMAs), the benefits will not necessarily be doubled.

The doubling of the benefit bounds any contribution that would be expected from the external events effects. The following summarizes the IPEEE at Surry:

The high winds and external flooding analyses performed for the IPEEE resulted in the finding that the plant is adequately designed to protect against the effects of these natural events. The plant is not designed to the latest probable maximum precipitation criteria. However, the analysis of this phenomenon shows that the plant is not vulnerable to core damage from such a storm because no safe shutdown equipment fails during the 1hr - 1mi2 PMP. Transportation and nearby facility accidents are not potential sources of damage at the plant because it is still in a very rural area with no major roads or facilities within the exclusion area of the plant. The other external events were evaluated and found to be insignificant contributors to CDF. There is military aviation traffic, primarily helicopters near the plant. However, based on a conservative PRA analysis, as recommended in the SRP, it is very unlikely that an accident would occur.

The total fire contribution to CDF is 5.0E-6/year. The total seismic contribution to CDF is 8.0E-6/yr. Therefore, the total CDF from external events is 1.3E-5/year.

The external events contribution of 1.3E-5/year compares to a base CDF of 3.7E-5/year from the internal events model used to calculate SAMA benefit. Therefore, the doubling approach is considered conservative since an argument could me made that the internal events benefit numbers would only need to be increased by as little as 35% to account for the external events contribution.

The maximum theoretical benefit (also called Maximum Attainable Benefit, or MAB) is based upon the elimination of all plant risk and equates to the previously calculated base case risk. The monetary value of the risk associated with those SAMAs that involve major plant modifications may simply be compared with this benefit as a means of eliminating them from further consideration (e.g., a SAMA that would require construction of a large structure might be compared with the MAB).

The SAMA cost estimates do not always require rigorous effort, since the benefit from many of the SAMAs is found to be much less than even an order of magnitude estimate of the cost. Detailed cost estimating is only applied in those situations in which the benefit is significant and application of judgement would be questioned. If a SAMA involved a hardware modification, it was assumed that the cost would be at least $100,000. For the generation of a new procedure and its implementation, it was assumed that the cost would be at least $30,000.

G.2.4 Sensitivity Analyses

The PRA calculations of SAMA benefit are recognized to have some uncertainty around the mean frequencies used in the analyses. Some of the uncertainty is related to quantifiable uncertainty distributions of the data, while other stems from unquantifiable uncertainty in the PRA assumptions. To account for the possible uncertainty, rather than perform a quantitative uncertainty analysis, the following sensitivity analyses were performed to bound the analysis.

NUREG/BR-0184 recommends using a 7% real (i.e., inflation-adjusted) discount rate for value-impact analysis and notes that a 3% discount rate should be used for sensitivity analysis to indicate the sensitivity of the results to the choice of discount rate. This reduced discount rate takes into account the additional uncertainties (i.e., interest rate fluctuations) in predicting costs for activities that would take place several years in the future. Analyses presented in Section G.2.3 used the 7% discount rate in calculating benefits of all the unscreened SAMAs. Dominion performed a sensitivity analysis by substituting the lower discount rate and recalculating the benefit of the candidate SAMAs. In addition, a sensitivity case was run using a 15% discount rate, which is judged to be more realistic for Dominion.

Nine additional sensitivity cases were analyzed, each varying an aspect of the MAACS input deck. The base case in Section G.2.3 used the best estimate values with year 2030 population projections, 1998 meteorological data and assumes 100% population evacuation. A sensitivity run on evacuation modeling was carried out by assuming an evacuation scenario wherein 95% of the population are evacuated normally and 5% are not evacuated at all (within the 10 mile emergency zone). Two sensitivity runs were made using 1997 and 1996 meteorological data respectively. Two more sensitivity runs were made using a 10% increase and a 50% decrease in the source term energy (MACCS parameter PLHEAT) respectively. Two more sensitivity runs were made using a 50% increase and 50% decrease in the timing data for the MACCS parameters OALARM, PLDUR and PDELAY. One sensitivity run was made for the time to take shelter (MACCS parameter DLTSHL) which used 5400 seconds, whereas the base case used 7200 seconds. The last sensitivity case used a multiplier of 1.46 vs. 1.17 for the farm and non-farm decontamination parameters CDFRM and CDNFRM in the CHRONC input file.

A summary of the sensitivity cases is as follows:

Case 1 - 3% Discount Rate

Case 2 - 15% Discount Rate

Case 3 - MAACS Input Sensitivity: 95% Evac

Case 4 - MAACS Input Sensitivity: 1997 Met Data

Case 5 - MAACS Input Sensitivity: 1996 Met Data

Case 6 - MAACS Input Sensitivity: +10% ST PLHEAT

Case 7 - MAACS Input Sensitivity: -50% ST PLHEAT

Case 8 - MAACS Input Sensitivity: +50% Timing

Case 9 - MAACS Input Sensitivity: -50% Timing

Case 10 - MAACS Input Sensitivity: DLTSHL= 5400

Case 11 - MAACS Input Sensitivity: CDFRM & CDNFRM x 1.46

The benefits calculated for each of these sensitivities are presented in Table G.2-3. As seen in the table, all of the sensitivity cases result in less than a factor of 2 increase in the benefit calculation. Table G.2-2 showed that all of the SAMAs screened with costs at least twice the benefit, so it is concluded that the cost-benefit results hold true even when the many uncertainties are considered.

Table G.2-1
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
1	Cap downstream piping of normally closed CCW drain and vent valves	Reduces the frequency of loss of CCW initiating event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.	(13)	A	Screened out
2	Enhance Loss of CCW procedure to facilitate stopping RCPs	Reduces potential for RCP seal damage due to pump bearing failure	(2), (10), (13)	C	Screened out
3	Enhance Loss of CCW procedure to present desirability of cooling down RCS prior to seal LOCA	Potential reduction in the probability of RCP seal failure.	(2)	C	Screened out
4	Additional training on the Loss of CCW	Potential improvement in success rate of operator actions after a loss of CCW.	(2)	C	Screened out
5	Provide hardware connections to allow another SW to cool charging pump seals	Reduce effect of loss of CCW by providing a means to maintain the charging pump seal injection after a loss of CCW. Note, in Watts Bar, this capability was already there for one charging pump at one unit, and the potential enhancement identified was to make it possible for all the charging pumps.	(2), (6), (11), (13)	C	Screened out
6	On loss of SW, proceduralize shedding CCW loads to extend the CCW heatup time	Increase time before the loss of CCW (and RCP seal failure) in the loss of ERCW sequences.	(2)	C	Screened out
7	Increase charging pump lube oil capacity	Would lengthen time before charging pump failure due to lube oil overheating in loss of CCW sequences	(2)	C	Screened out

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
8	Eliminate RCP thermal barrier dependence on CCW, such that loss of CCW does not result directly in core damage.	Would prevent loss of RCP seal integrity after a loss of CCW. Watts Bar IPE said this could be done with SW connection to charging pump seals.	(2), (13)	C	Screened out
9	Provide additional SW pump	Providing another pump would decrease core damage frequency due to a loss of SW	(5)		The SPS Service Water system is fed by the canal inventory. The eight circ water pumps are enough to judge that another would not be beneficial. The 3 emergency service water pumps are not usually needed except in certain rare situation. However, this item will be retained for a cost-benefit analysis on the emergency service water pumps.
10	Create an independent RCP seal injection system, with dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of seal cooling or SBO.	(6), (11), (13)		Not initially screened. Considered further in the cost-benefit analysis.
11	Create an independent RCP seal injection system, without dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of seal cooling, but not SBO.	(11)		Not initially screened. Considered further in the cost-benefit analysis.
12	Use existing hydro test pump for RCP seal injection	Independent seal injection source, without cost of a new system	(7)	A	Screened out
13	Replace ECCS pump motors with air cooled motors	Remove dependency on CCW	(10), (13)	C	Screened out
14	Install improved RCP seals	RCP seal O-rings constructed of improved materials would reduce chances of RCP seal LOCA	(11), (13)		Not initially screened. Considered further in the cost-benefit analysis.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
15	Add a third CCW pump	Reduce chance of loss of CCW	(13)		Not initially screened. Considered further in the cost-benefit analysis.
16	Prevent charging pump flow diversion from the relief valves	If relief valve opening causes a flow diversion large enough to prevent RCP seal injection, then modification can reduce frequency of loss of RCP seal cooling.	(13)	A	Screened out
17	Change procedures to isolate RCP seal letdown flow on loss of CCW, and guidance on loss of injection during seal LOCA.	Reduce CDF from loss of seal cooling.	(13)	C	Screened out
18	Procedures to stagger charging pump use after a loss of SW	Allow high pressure injection to be extended after a loss of SW	(13)	C	Screened out
19	Use firewater pumps as a backup seal injection and high pressure makeup	Reduce RCP seal LOCA frequency and SBO core damage frequency	(13)	A	Screened out. This SAMA is considered not feasible since the fire pumps cannot deliver sufficient head to provide seal injection.
20	Procedural guidance for use of cross-tied CCW or SW pumps	Can reduce the frequency of the loss of either of these.	(13)	B	Screened out. The CCW system is already cross tied between loops and between the two SPS units.
21	Procedure & operator training enhancements in support system failure sequences, with emphasis on anticipating problems and coping.	Potential improvement in success rate of operator actions after support system failures.	(2), (13)	Grouped into a category called "Loss of CCW or SW procedural enhancements"	Not initially screened. Considered further in the cost-benefit analysis.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
22	Improve ability to cool RHR heat exchangers	Reduced chance of loss of DHR by 1)Performing procedure and hardware modification to allow manual alignment of fire protection system to the CCW system, or 2)Installing a CCW header cross-tie	(12), (13)	A for the first option; B for the second option	The first is screened out because the fire water system does not have sufficient flow to cool the RHR heat exchangers. The second is screened because the CCW system is already cross-tied between loops and between units.
23	Alter circ water valve power supply arrangement	Because all eight waterboxes have a valve powered by 1J1-1A, its failure challenges all eight waterboxes to isolate. By changing the power supplies on the 2-CN-SC-1A and 1B waterboxes to 2J1-1A, a failure of the 1J bus will only challenge 4 waterboxes.	Suggested by the SPS PRA staff or from the review of the top 100 cutsets		After a LOOP, the CW valves will be powered from the #3 diesel whether it aligns to the 1J or 2J bus. However, this item will be evaluated in the cost-benefit analysis to see if the non-LOOP cases have any significant benefit.
24	Stage backup fans in Switchgear rooms	Provides alternate ventilation in the event of a loss of switchgear ventilation.	(13)	A	This item is screened on the basis that fans alone would not remove the heat from the Switchgear rooms. Some method of heat removal would be required, as evaluated in item 25.
25	Provide redundant train of ventilation to 480V board room.	Would improve reliability of 480V HVAC. At Watts Bar, only one train of HVAC cools the 480V board room that contains the unit vital inverters, and recovery actions are heavily relied on. Watts Bar IPE said their corrective action program is dealing with this	(2), (13)	Recategorized as "Provide a non-safety related, redundant train of switchgear ventilation"	Not initially screened. Considered further in the cost-benefit analysis.
26	Procedures for temporary HVAC	Provides for improved credit to be taken for loss of HVAC sequences	(11), (13)	B	Screened out.
27	Add a switchgear room high temp alarm	Improve diagnosis of a loss of switchgear HVAC	(13)		Not initially screened. Considered further in the cost-benefit analysis.

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
28	Create ability to switch fan power supply to DC in SBO	(was created for a BWR RCIC room, Fitzpatrick; possible for turbine AFW if has its own fan) Allow continued operation in SBO	(13)	A (Surry's turbine AFW can operate during an SBO)	Screened out.
29	Delay containment spray actuation after large LOCA	When ice remains in the ice condenser at such plants, containment sprays have little impact on containment performance, yet rapidly drain down the RWST. This improvement would lengthen time of RWST availability.	(2), (6)	A	Screened out.
30	Install containment spray throttle valves	Can extend the time over which water remains in the RWST, when full containment spray flow is not needed.	(11), (12), (13)		Not initially screened. Considered further in the cost-benefit analysis.
31	Install an independent method of suppression pool cooling	Would decrease frequency of loss of containment heat removal	(3), (4)	A	Screened out.
32	Develop an enhanced containment spray system	Would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal	(3), (4), (16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
33	Provide a dedicated existing containment spray system	Identical to the previous concept, except that one of the existing spray loops would be used instead of developing a new spray system.	(3), (4), (5), (6), (11)		Not initially screened. Considered further in the cost-benefit analysis.
34	Install a containment vent large enough to remove ATWS decay heat	Assuming injection is available, would provide alternative decay heat removal in an ATWS	(3), (4)		Not initially screened. Considered further in the cost-benefit analysis.
35	Install a filtered containment vent to remove decay heat	Assuming injection is available (non-ATWS sequences), would provide alternate decay heat removal with the released fission products being scrubbed.	(3), (4) (similar options in (5), (6), (8), (11), (12), (16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
36	Install an unfiltered hardened containment vent	Provides an alternate decay heat removal method (non-ATWS), which is not filtered	(3), (4), (9), (14)		Not initially screened. Considered further in the cost-benefit analysis.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
37	Create/enhance hydrogen ignitors with independent power supply.	Use either a new, independent power supply, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies such as the security system diesel. Would reduce hydrogen detonation at lower cost.	(3), (5), (6), (7), (9), (12), (13), (14), (15), (16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
38	Create a passive hydrogen ignition system	Reduce hydrogen detonation potential without requiring electric power	(7), (11), (16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
39	Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris	A molten core escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a meltthrough.	(3), (4), (16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
40	Create a water cooled rubble bed on the pedestal	This rubble bed would contain a molten core dropping onto the pedestal, and would allow the debris to be cooled.	(3), (4), (8), (16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
41	Provide modification for flooding of the drywell head	Would help mitigate accidents that result in leakage through the drywell head seal	(4), (9)	A	Screened out.
42	Enhance fire protection system and/or standby gas treatment system hardware and procedures	Improve fission product scrubbing in severe accidents	(4)		Not initially screened. Considered further in the cost-benefit analysis.
43	Create a reactor cavity flooding system	Would enhance debris coolability, reduce core concrete interaction and provide fission product scrubbing	(5), (6), (9), (11), (12), (13), (15), (16), (17)		Not initially screened. Considered further in the cost-benefit analysis.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
44	Creating other options for reactor cavity flooding	(a) Use water from dead-ended volumes, the condensed blowdown of the RCS, or secondary system by drilling pathways in the reactor vessel support structure to allow drainage from the steam generator compartments, refueling canal, sumps, etc., to the reactor cavity. Also (for ice condensers), allow drainage of water from melted ice into the reactor cavity. (b) Flood cavity via systems such as diesel driven fire pumps	(7), (9), (13)	(a) - the ice condenser portion of this alternative is not applicable to SPS	Part b is not initially screened. Considered further in the cost-benefit analysis.
45	Enhance air return fans (ice condenser containment)	Provide an independent power supply for the air return fans, reducing containment failure in SBO sequences	(6), (11)	A	Screened out.
46	Provide a core debris control system	Would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and containment shell.	(6), (11)		Not initially screened. Considered further in the cost-benefit analysis.
47	Create a core melt source reduction system (COMSORS)	Place enough glass underneath the reactor vessel such that a molten core falling on the glass would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur (such benefits are theorized in the reference).	(19)		Not initially screened. Considered further in the cost-benefit analysis.
48	Provide containment inerting capability	Would prevent combustion of hydrogen and carbon monoxide gases	(6), (9), (11), (14)		Not initially screened. Considered further in the cost-benefit analysis.
49	Use fire water spray pump for containment spray	Redundant containment spray method without high cost	(7), (9), (10), (12)		Not initially screened. Considered further in the cost-benefit analysis.
50	Install a passive containment spray system	Containment spray benefits at a very high reliability, and without support systems	(8)		Not initially screened. Considered further in the cost-benefit analysis.
51	Secondary containment filtered ventilation	For plants with a secondary containment, would filter fission products released from the primary containment	(8)	A	Screened out.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
52	Increase containment design pressure	Reduce chance of containment overpressure	(8)	A (this improvement is intended for a new plant)	Screened out.
53	Increase the depth of the concrete basemat, or use an alternative concrete material to ensure melt through does not occur	Prevent basemat melt through	(16), (17)	A (this improvement is intended for a new plant)	Screened out
54	Provide a reactor vessel exterior cooling system.	Potential to cool a molten core before it causes vessel failure, if the lower head can be submerged in water.	(16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
55	Create another building, maintained at a vacuum to be connected to containment	In an accident, connecting the new building to containment would depressurize containment and reduce any fission product release.	(17)		Not initially screened. Considered further in the cost-benefit analysis.
56	Add ribbing to the containment shell	Would reduce the chance of buckling of containment under reverse pressure loading.	(17)	A (this improvement is intended for a new plant)	Screened out.
57	Train operations crew for response to inadvertent actuation signals	Improves chances of a successful response to the loss of two 120V AC buses, which causes inadvertent signals.	(13)	B	Screened out.
58	Proceduralize alignment of spare diesel to shutdown board after LOP and failure of the diesel normally supplying it	Reduced SBO frequency.	(2)	B	Screened out.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
59	Provide an additional diesel generator	Would increase on-site emergency AC power reliability and availability (decrease SBO)	(5), (6), (10), (13) (16), (17)	B	Screened out. SPS already has installed an SBO diesel.
60	Provide additional DC battery capability	Would ensure longer battery capability during a SBO, reducing frequency of long term SBO sequences.	(5), (6), (13), (16), (17)	B	Screened out. This capability already exists at Surry in the form of the 'Black' battery.
61	Use fuel cells instead of lead-acid batteries	Extend DC power availability in a SBO	(16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
62	Procedure to cross tie HPCS diesel	(BWR 5/6)	(10)	A	Screened out.
63	Improved bus cross tie ability	Improved AC power reliability	(10), (13)	B	There is already a cross-tie ability between the buses at each SPS unit, and further cross-tie features would have minimal benefit.
64	Alternate battery charging capability	Improved DC power reliability. Either cross tie of AC buses, or a portable diesel-driven battery charger.	(10), (11), (12), (13)	The bus cross-tie portion is grouped into a category "Improved bus cross-tie ability"	Not initially screened. Considered further in the cost-benefit analysis.
65	Increase/improve DC bus load shedding	Improved battery life in station blackout	(10), (11), (12), (13)	B	SPS procedures already direct appropriate DC load shedding during an SBO.
66	Replace batteries	Improved reliability	(10)	A	Screened out. Recent Surry data has not shown any vulnerability from battery reliability, so no benefit would be recognized.
67	Create AC power cross tie capability across units	Improved AC power reliability	(11), (12), (13)	B	There is already substantial cross-tie abilities between the SPS units, and further cross-tie features would to have minimal benefit.

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
68	Create a cross-unit tie for diesel fuel oil	Adds diesel fuel oil redundancy.	(13)	B	At Surry, the cross-tie already exists with the installation of a spool piece. No further action is required on this mod.
69	Develop procedures to repair or change out failed 4KV breakers	Offers a recovery path from a failure of breakers that perform transfer of 4.16 kV non-emergency buses from unit station service transformers to system station service transformers, leading to loss of emergency AC power (i.e., in conjunction with failures of the diesel generators).	(13)		Not initially screened. Considered further in the cost-benefit analysis.
70	Emphasize steps in recovery of offsite power after a SBO.	Reduced human error probability of offsite power recovery.	(13)		Not initially screened. Considered further in the cost-benefit analysis.
71	Develop a severe weather conditions procedure	For plants that do not already have one, reduces the likelihood of external events CDF.	(13)	B	Screened out.
72	Procedures for replenishing diesel fuel oil	Allow long term diesel operation	(13)	A	This item is screened out because the diesel fuel tanks are already large enough to provide fuel well beyond the PRA assumed mission time of 24 hours.
73	Install gas turbine generators	Improve on-site AC power reliability	(13)	B	This feature is already installed at Surry in the form of the Gravel Neck C/T's. In addition, Surry has installed an SBO diesel for extra emergency power reliability. Therefore, this item is screened out.
74	Install tornado protection on gas turbine generator	If the unit has a gas turbine, the tornado-induced SBO frequency would be reduced.	(16), (17)	A	Screened out.
75	Create a river water backup for diesel cooling.	Provides redundant source of diesel cooling.	(13)	A - diesels are air cooled	Screened out.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
76	Use firewater as a backup for diesel cooling	Redundancy in diesel support systems	(13)	A - diesels are air cooled	Screened out.
77	Provide a connection to alternate offsite power source (the Gravel Neck fossil units)	Increase offsite power redundancy	(13) and suggested by the SPS PRA staff		Not initially screened. Considered further in the cost-benefit analysis.
78	Implement underground offsite power lines	Could improve offsite power reliability, particularly during severe weather.	(13)	A	In order for underground offsite power lines to provide real protection from severe weather, the high voltage lines would have to be installed not only in the SPS-controlled area, but also throughout the offste distribution grid. Such a plan is clearly not feasible, so this item is screened.
79	Replace anchor bolts on diesel generator oil cooler	Millstone found a high seismic SBO risk due to failure of the diesel oil cooler anchor bolts. For plants with a similar problem, this would reduce seismic risk.	(13)	B	Screened out
80	Provide ability for alternate bus loading by diesels	The 1H bus has one dedicated diesel; 1J has a swing diesel plus the AAC diesel; 2H has a dedicated diesel plus the AAC diesel; 2J has just the swing diesel. This leaves the 2J bus somewhat more vulnerable to a LOOP than the others.	Suggested by the SPS PRA staff or from the review of the top 100 cutsets	A	Surry requires that the SBO diesel start and auto-load on one of two buses within ten seconds. However, the required CW valves which are powered from the 2J bus retain power no matter which way the J bus aligns. This would negate the need for this mod. Once an additional bus is added to the loading scheme, the automatic selection of which bus to align to becomes nearly impossible. No further action on this mod is required.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
81	Alter electric power dependency to BC and CC SW valves	These valves require closing after a LOOP	Suggested by the SPS PRA staff or from the review of the top 100 cutsets		Not initially screened. Considered further in the cost-benefit analysis.
82	Relocate transfer buses to different rooms	All of the transfer buses are located within the same room, which results in a high CDF fire sequence.	Suggested by the SPS PRA staff or from the review of the top 100 cutsets		Not initially screened. Considered further in the cost-benefit analysis.
83	Put a fast acting MG output breaker on both units	With a fast acting breaker, a turbine runback would be possible, reducing the likelihood of a reactor trip in some cases.	Suggested by the SPS PRA staff or from the review of the top 100 cutsets		Not initially screened. Considered further in the cost-benefit analysis.
84	Proceduralize use of pressurizer vent valves during SGTR sequences	SPS procedures direct the use of pressurizer sprays to reduce RCS pressure after a SGTR. Use of the vent valves provides a backup method.	(13)	A	Screened out because the vent valves are too small to provide adequate pressure relief.
85	Install a redundant spray system to depressurize the primary system during a SGTR.	Enhanced depressurization ability during SGTR.	(16), (17)	B	This feature is already installed in the plant. The charging pumps have an existing line that feeds water from the VCT directly to the pressurizer spray nozzles. Some operating restrictions apply related to nozzle delta temperature. In a severe accident scenario nozzle damage may be an acceptable equipment casualty. No further action is required for this modification.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
86	Improved SGTR coping abilities	Improved instrumentation to detect SGTR, or additional systems to scrub fission product releases.	(7), (9), (10), (13), (14), (16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
87	Adding other SGTR coping features	(a) A highly reliable (closed loop) steam generator shell-side heat removal system that relies on natural circulation and stored water sources, (b) a system which returns the discharge from the steam generator relief valve back to the primary containment, (c) an increased pressure capability on the steam generator shell side with corresponding increase in the safety valve setpoints.	(7), (8), (17)	A	Screened out. Parts (a) and (c) are screened as not being feasible for an existing plant. Part (b) is also screened because adding such a steam load to the containment building would require a redesign of the containment pressure capacity.
88	Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift	SGTR sequences would not have a direct release pathway	(8), (17)		Not initially screened. Considered further in the cost-benefit analysis.
89	Replace steam generators with new design	Lower frequency of SGTR	(13)		Not initially screened. Considered further in the cost-benefit analysis.
90	Revise EOPs to direct that a faulted steam generator be isolated.	For plants whose EOPs don’t already direct this, would reduce consequences of a SGTR	(13)	B	Screened out. SPS procedures already direct this.
91	Direct steam generator flooding after a SGTR, prior to core damage.	Would provide for improved scrubbing of SGTR releases.	(14), (15)	B	Screened out. SPS procedures already direct this.
92	A maintenance practice that inspects 100% of the tubes in a steam generator	Reduce chances of tube rupture	(16), (17)	A	Inspecting 100% of the tubes in each steam generator would result in a substantial dosage incurred by personnel every outage, and is judged to offset any possible benefit in reduced SGTR frequency.

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
93	Locate RHR inside of containment	Would prevent ISLOCA out the RHR pathway	(8)	A - this item is not applicable to an existing plant	Screened out.
94	Self-actuating containment isolation valves	For plants that don't have this, it would reduce the frequency of isolation failure	(8)	B	Screened out.
95	Additional instrumentation and inspection to prevent ISLOCA sequences	Install additional instrumentation for detecting ISLOCA events. Implement a comprehensive piping inspection program to detect precursors to breaches in RCS integrity. The benefit assumes that the programs are so effective all ISLOCAs are eliminated.	(5), (6), (11), (13)	A	This mod is not feasible. Existing inspection activities could not identify ISLOCA precursors using a sampling technique. 100% inspection at each outage is not feasible since many of the inspections require the complete disassembly of valves, pumps and other complex components. This would significantly extend the duration of each outage. Even if a 100% inspection program could be instituted, the failures that cause ISLOCAs may go from generation of an initial fault to complete failure within one refueling cycle.

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
96	Increase frequency of valve leak testing	Decrease ISLOCA frequency	(12)	A	This mod is not feasible. The dominant ISLOCA sequence involves failure of the LHSI valves, which are currently tested on a sampling frequency. The two valves in one line are tested each outage. There are a total of three lines and six valves. Valve testing was recently reduced to the sampling technique for two reasons. 1) Costs for running the test are very high. 2) Test results and disassembly inspections have confirmed that these valves remain in excellent condition. The testing of these valves occurs on critical path during an outage, is very expensive to run and is a high dose activity.
97	Improvement of operator training on ISLOCA coping	Decrease ISLOCA effects	(12), (13)	A	The dominant ISLOCA sequence at SPS is an unisolable ISLOCA, so additional training is expected to have a very small benefit.
98	Install relief valves in the component cooling water system	Would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA	(13)	A	Screened out.
99	Provide leak testing of valves in ISLOCA paths	At Kewaunee, four MOVs isolating RHR from the RCS were not leak tested. Will help reduce ISLOCA frequency	(13)	B	Screened out. As described in item 96, the valves are already tested.
100	Revise EOPs to improve ISLOCA identification	Salem had a scenario in which an RHR ISLOCA could direct initial leakage back to the PRT, giving indication that the LOCA was inside containment. Procedure enhancement would ensure LOCA outside containment would be observed.	(13)	B	Screened out.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
101	Ensure all ISLOCA releases are scrubbed	Would scrub ISLOCA releases. One suggestion was to plug drains in the break area so the break point would cover with water.	(14), (15)		Not initially screened. Considered further in the cost-benefit analysis.
102	Add redundant and diverse limit switch to each containment isolation valve.	Enhanced isolation valve position indication, which would reduce frequency of containment isolation failure and ISLOCAs.	(16), (17)	A	The dominant ISLOCA sequence at SPS is due to failure of check valves, so a limit switch would not be effective.
103	Add a check valve downstream of the LHSI pumps on the cold leg injection line.	The ISLOCA frequency is dominated by the LHSI injection lines to the cold legs, which have 2 check valves each. Adding another check valve in the common injection line would essentially eliminate the frequency of the ISLOCA sequence through these pathways.	Suggested by the SPS PRA staff or from the review of the top 100 cutsets		Not initially screened. Considered further in the cost-benefit analysis.
104	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment	For a plant where internal flooding from turbine building to safeguards areas is a concern, this modification can prevent flood propagation.	(13)	B	Screened out.
105	Improve inspection of rubber expansion joints on main condenser	For a plant where internal flooding due to failure of circulating water expansion joint is a concern, this can help reduce the frequency.	(13)	B	Screened out.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
106	Internal flood prevention and mitigation enhancements	1) Use of submersible MOV operators. 2) Back flow prevention in drain lines.	(13)	A	Screened out. Submersible MOVs have already been evaluated as part of the IPE on a cost-benefit basis (Reference 21) and will not be reviewed further in this report. The SPS IPE identified drains where back flow prevention devices would provide noticeable benefit, and these were installed. Back flow devices in any other areas would provide negligible benefit.
107	Internal flooding improvements at Fort Calhoun	Prevention or mitigation of 1) A rupture in the RCP seal cooler of the CCW system, 2) An ISLOCA in a shutdown cooling line, 3) An AFW flood involving the need to possibly remove a watertight door. For a plant where any of these apply, would reduce flooding risk.	(13)	A	Screened out. The SPS flooding analyses did not show any significant CDF from any of these sequences, so these SAMAs do not apply to Surry.
108	Digital feedwater upgrade	Reduces chance of loss of MFW following a plant trip.	(13)	B	Screened out - this feature already exists at Surry.
109	Perform surveillances on manual valves used for backup AFW pump suction	Improves success probability for providing alternate water supply to AFW pumps.	(13)	A	Screened out.
110	Install manual isolation valves around AFW turbine driven steam admission valves	Reduces the dual turbine driven pump maintenance unavailability.	(13)	A	Screened out.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
111	Install accumulators for turbine driven AFW pump flow control valves	Provide control air accumulators for the turbine driven AFW flow control valves, the motor driven AFW pressure control valves, and S/G PORVs. This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOP.	(11)		Not initially screened. Considered further in the cost-benefit analysis.
112	Install a new Auxiliary Feedwater Storage Tank	Either replace old tanks with a larger ones, or install another backup tank	(13), (16), (17)	B	The Condensate Storage Tanks are cross-connected to the Emergency Condensate Storage Tanks via a gravity feed. The effective volume of the ECST includes most of the CST volume as well. Since this feature already exists, no further action on this mod is required.
113	Cooling of steam driven AFW pump in a SBO	1)Use firewater to cool pump, or 2)Make the pump self-cooled. Would improve success chances in a SBO	(13)	A	Screened out. Surry's turbine AFW can operate during an SBO.
114	Proceduralize local manual operation of AFW when control power is lost	Lengthen AFW availability in SBO. Also provides a success path should AFW control power be lost in non-SBO sequences.	(13)	B	Screened out. Procedure already exists at SPS.
115	Provide portable generators to be hooked in to the turbine driven AFW, after battery depletion	Extend AFW availability in a SBO (assuming the turbine-driven AFW requires DC power)	(16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
116	Add a motor train of AFW to the steam trains.	For PWRs that do not have any motor trains of AFW, this can increase reliability in non-SBO sequences.	(13)	B	Screened out.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
117	Create ability for emergency connections of existing or alternate water sources to feedwater/condensate	Would be a backup water supply for the feedwater/condensate systems.	(12)	B	The Condensate Storage Tanks are cross-connected to the Emergency Condensate Storage Tanks via a gravity feed. The effective volume of the ECST includes most of the CST volume as well. Since this feature already exists, no further action on this mod is required.
118	Use firewater as a backup for steam generator inventory	Would create a backup to main and auxiliary feedwater for steam generator water supply	(13)	A	The Condensate Storage Tanks are cross-connected to the Emergency Condensate Storage Tanks via a gravity feed. The effective volume of the ECST includes most of the CST volume as well. Since this feature already exists, no further action on this mod is required.
119	Procure a portable diesel pump for isolation condenser makeup	Backup to the city water supply and diesel fire water pump in providing isolation condenser makeup	(13)	A	Screened out.
120	Install an independent diesel for the condensate storage tank makeup pumps	Would allow continued inventory in CST during a SBO	(13)	A	The Condensate Storage Tanks are cross-connected to the Emergency Condensate Storage Tanks via a gravity feed. The effective volume of the ECST includes most of the CST volume as well. Since this feature already exists, no further action on this mod is required.
121	Change failure position of condenser makeup valve.	If the condenser makeup valve fails open on loss of air or power, this can prevent CST flow diversion to condenser. Allows greater inventory for the AFW pumps.	(13)	A	Screened out.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
122	Create passive secondary side coolers	Provide a passive heat removal loop with a condenser and heat sink. Would reduce CDF from the loss of feedwater.	(17)		Not initially screened. Considered further in the cost-benefit analysis.
123	Automate air bottle swap for S/G PORVs	Manual action is required to swap air source to the air bottles. Automatic swap on low pressure would eliminate the operator action.	Suggested by the SPS PRA staff or from the review of the top 100 cutsets		Not initially screened. Considered further in the cost-benefit analysis.
124	Condenser dump after SI	Utilize bypass around the main steam trip valves to use the condenser dump after an SI (the PRA assumes the function can not be recovered after an SI signal)	Suggested by the SPS PRA staff or from the review of the top 100 cutsets		Not initially screened. Considered further in the cost-benefit analysis.
125	Provide capability for diesel driven, low pressure vessel makeup	Extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., firewater)	(4), (5), (13)		Not initially screened. Considered further in the cost-benefit analysis.
126	Provide an additional high pressure injection pump with independent diesel	Reduce frequency of core melt from small LOCA sequences, and from SBO sequences.	(6), (16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
127	Install independent AC high pressure injection system	Would allow make up and feed and bleed capabilities during a SBO	(11)		Subsumed into "Provide an additional high pressure injection pump with independent diesel."
128	Create the ability to manually align ECCS recirculation	For plants that do not already have this, it provides a backup should automatic or remote operation fail	(12)	B	Screened out.

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
129	Implement an RWST makeup procedure	Decrease core damage frequency from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTR	(12), (13)	B	Screened out because this feature already exists. The use of the PG tanks along with the BASTs is already installed. Furthermore, there is a cross-connect from the opposite unit's RWST.
130	Stop low pressure injection pumps earlier in medium or large LOCAs	Would give more time to perform recirculation swapover.	(13)	A	Screened out. This is not feasible. Raising the low level setpoint reduces the total useable volume of the RWST. This negatively affects the containment analysis which relies on cold RWST water to return the containment to subatmoshpheric within one hour after an event. In addition, an automatic swap exists so operator reliability is not an issue
131	Emphasize timely recirc swapover in operator training	Reduce human error probability of recirculation failure	(13)	B	Screened out. SPS has an automatic swap.
132	Upgrade CVCS to mitigate small LOCAs	For a plant like the AP600 where CVCS can't mitigate small LOCA, an upgrade would decrease CDF from small LOCA	(8)	B	Screened out.
133	Install an active high pressure SI system	For a plant like the AP600, where an active high pressure injection system does not exist, would add redundancy in high pressure injection.	(8)	B	Screened out.
134	Change "in-containment" RWST suction from 4 check valves to 2 check and 2 air operated valves	Remove common mode failure of all four injection paths	(8)	A	Screened out.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
135	Replace two of the four safety injection pumps with diesel pumps	Intended for System 80+, which has four trains of SI. This would reduce common cause failure probability.	(16), (17)	A	Screened out.
136	Align LPCI or core spray to CST on loss of supp pool cooling	Low pressure ECCS can be maintained in loss of suppression pool cooling scenarios	(10), (13)	A	Screened out.
137	Raise HPCI/RCIC backpressure trip setpoints	Ensures HPCI/RCIC availability when high suppression pool temperatures exist.	(13)	A	Screened out.
138	Improve the reliability of the ADS	Reduce frequency high pressure core damage sequences	(4)	A	Screened out.
139	Disallow automatic vessel depressurization in non-ATWS scenarios	Improve operator control of plant.	(13)	A	Screened out.
140	Create automatic swapover to recirculation on RWST depletion	Would remove human error contribution from recirculation failure.	(5), (6), (11)	B	Screened out.
141	Enlarge the RWST	Greater water capacity for injection	Suggested by the SPS PRA staff or from the review of the top 100 cutsets	A/B	This SAMA is screened because SPS already has makeup capability to the RWST (see item 128) and has an automatic swap to recirculation.
142	Modify EOPs for ability to align diesel power to more air compressors.	For plants which do not have diesel power to all normal and backup air compressors, this change allows increased reliability of instrument air after a LOP.	(13)	A	Screened out.
143	Replace old air compressors with more reliable ones.	Improve reliability and increase availability of instrument air compressors.	(13)	A	Screened out. Recent Surry data has not shown any vulnerability from air compressor reliability, so no benefit would be recognized.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
144	Install Nitrogen bottles as backup gas supply for SRVs	Extend operation of Safety Relief Valves during SBO and loss of air events (BWRs)	(13)	A	Screened out.
145	Install MG set trip breakers in control room	Provides trip breakers for the motor generator sets in the control room. Currently, at Watts Bar, an ATWS would require an immediate action outside the control room to trip the MG sets. Would reduce ATWS CDF	(11)		Not initially screened. Considered further in the cost-benefit analysis.
146	Add capability to remove power from the bus powering the control rods	Decrease time to insert control rods if the reactor trip breakers fail (during a loss of feedwater ATWS which has rapid pressure excursion).	(13)		Grouped into the category "Install MG set trip breakers in control room"
147	Create cross-connect ability for standby liquid control (SLC) trains	Improved reliability for boron injection during ATWS	(13)	A	Screened out.
148	Create an alternate boron injection capability (backup to SLC)	Improved reliability for boron injection during ATWS	(13)	A	Screened out.
149	Remove or allow override of LPCI injection during ATWS	On failure of HPCI and condensate, the Susquehanna units direct reactor depressurization followed by 5 minutes of automatic LPCI injection. Would allow control of LPCI immediately.	(13)	A	Screened out.
150	A system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	Would improve equipment availability after an ATWS.	(16), (17)	B	Screened out.
151	Create a boron injection system to back up the mechanical control rods.	Provides a redundant means to shut down the reactor.	(16), (17)	B	Screened out.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
152	Provide an additional I&C system (e.g., AMSAC).	Improve I&C redundancy and reduce ATWS frequency.	(16), (17)	B	Screened out. (AMSAC already implemented at Surry)
153	Provide capability for remote operation of secondary side PORVs in SBO	Manual operation of these valves is required in a SBO scenario. High area temperatures may be encountered in this case (no ventilation to main steam areas), and remote operation could improve success probability.	(2)	B	Screened out because SPS already has this feature.
154	Create/enhance reactor coolant system depressurization ability	Either with a new depressurization system, or with existing PORVs, head vents and secondary side valve, RCS depressurization would allow low pressure ECCS injection. Even if core damage occurs, low RCS pressure alleviates some concerns about high pressure melt ejection.	(5), (6), (9), (11), (12), (13), (14), (15), (16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
155	Make procedural changes only for the RCS depressurization option	Reduce RCS pressure without cost of a new system	(7), (9), (13)		Subsumed into "Create/enhance reactor coolant system depressurization ability"
156	Defeat 100% load rejection capability	Eliminates the possibility of a stuck open PORV after a LOP, since PORV opening wouldn't be needed	(13)	A	This item is not applicable to SPS since SPS does not have 100% load rejection capability.
157	Change CRD flow control valve failure position	Change failure position to the 'fail-safest' position	(13)	A	Screened out.
158	Secondary side guard pipes up to the MSIVs.	Would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. Would also guard against or prevent consequential multiple SGTR following a main steam line break event.	(16), (17)		Not initially screened. Considered further in the cost-benefit analysis.
159	Digital large break LOCA protection	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (a leak before break).	(17)		Not initially screened. Considered further in the cost-benefit analysis.

Table G.2-1 (continued)
Initial List of Candidate Improvements for the SPS SAMA Analysis

SAMA Number	Potential Improvement	Discussion	Reference (see Section G.2.5)	Screening criterion or grouping (see Section G.2.2)	Evaluation
160	Increase seismic capacity of the plant to a HCLPF of twice the SSE	Reduced seismic CDF	(17)	A (this improvement is intended for a new plant)	Screened out.

Table G.2-2
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
9	Provide additional SW pump	Providing another pump would decrease core damage frequency due to a loss of SW	2.0%	0.3%	$34k	>2 x Benefit	Screen Out	Analysis case SWP determined the maximum benefit to be $34k. Not cost-beneficial; cost is expected to exceed twice the benefit.
10	Create an independent RCP seal injection system, with dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of seal cooling or SBO.	4.0%	0.3%	$63k	>2 x benefit	Screen out	Analysis case SLO determined the maximum benefit to be $63k. Not cost-beneficial; cost is expected to exceed twice the benefit.
11	Create an independent RCP seal injection system, without dedicated diesel	Would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of seal cooling, but not SBO.	4.0%	0.3%	$63k	>2 x benefit	Screen out	Analysis case SLO determined the maximum benefit to be $63k. Not cost-beneficial; cost is expected to exceed twice the benefit.
14	Install improved RCP seals	RCP seal O-rings constructed of improved materials would reduce chances of RCP seal LOCA	4.0%	0.3%	$63k	>2 x benefit	Screen out	Analysis case SLO determined the maximum benefit to be $63k. Not cost-beneficial; cost is expected to exceed twice the benefit.
15	Add a third CCW pump	Reduce chance of loss of CCW	0.02%	0.3%	$5k	>2 x benefit	Screen out	Analysis case CCP determined the maximum benefit to be $5k. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
21	Loss of CCW or SW procedural enhancements	The suggested improvements in the reference documents include staggering CCW pump operation when SW fails, cross-tying pumps, or shedding CCW loads to extend heatup time.	0.02%	0.3%	$5k	>2 x benefit	Screen out	The cross-tied system already exists at SPS. The other options would not provide any significant benefit because although they might delay system failure slightly, they would not prevent it. Analysis case CCP further demonstrates the low benefit from even a significant change to the CC system, showing a benefit of on only $5k if a new, completely independent, pump were added. Not cost-beneficial; cost is expected to exceed twice the benefit.
23	Alter circ water valve power supply arrangement	The circ water valve inlet/outlet power supplies are 1J-A/1H and 1J-A/2H. The reliability during a LOOP could be improved by having one of the 1J-A supplies changed to 1H	-0.5%	-0.08%	-$4k	>2 x benefit	Screen out	Analysis case CWV showed that there is actually an increase to the CDF and offsite release by rearranging these power supplies. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
25	Provide a non-safety related, redundant train of switchgear ventilation	Provide a non-safety related, redundant train of switchgear ventilation	13.9%	5.0%	$278k	>2 x benefit	Screen out	Analysis case HVC determined the maximum benefit to be $278k. The critical cost is associated with finding room for the AHUs within the Control Room envelope. The AHUs would need to be located outside the existing envelope in an airtight pressure retaining enclosure and ducted through the envelope walls. Use of the existing ductwork would not be feasible nor would installation of new ductwork to support the operation of these new AHUs. They would simply terminate at the envelope walls for both their suction and return air flows. Space for the equipment outside the envelope may not be available making this modification not feasible. If space could be found, the cost for relocation of existing equipment for space considerations and then installation of this system would be $15-25M. Not cost-beneficial; cost is expected to exceed twice the benefit.
27	Add a switchgear room high temp alarm	Improve diagnosis of a loss of switchgear HVAC	0.02%	0.00%	<$1k	>2 x benefit	Screen out	Analysis case HVA determined the maximum benefit to be less than $1k. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
30	Install containment spray throttle valves	Can extend the time over which water remains in the RWST, when full containment spray flow is not needed.	0.00%	0.00%	$0	>2 x benefit	Screen out	Analysis case CSP shows a no benefit from this SAMA.
32	Develop an enhanced containment spray system	Would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal	0.00%	0.00%	$0	>2 x benefit	Screen out	Analysis case CSP shows a no benefit from this SAMA.
33	Provide a dedicated existing containment spray system	Identical to the previous concept, except that one of the existing spray loops would be used instead of developing a new spray system.	0.00%	0.00%	$0	>2 x benefit	Screen out	Analysis case CSP shows a no benefit from this SAMA.
34	Install a containment vent large enough to remove ATWS decay heat	Assuming injection is available, would provide alternative decay heat removal in an ATWS	4.9%	1.6%	$90k	>2 x benefit	Screen out	Analysis case DHR determined the maximum benefit to be less than $90k. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
35	Install a filtered containment vent to remove decay heat	Assuming injection is available (non-ATWS sequences), would provide alternate decay heat removal with the released fission products being scrubbed.	4.9%	5.5%	$135k	>2 x benefit	Screen out	Analysis case DHR shows the maximum possible benefit of a containment vent as $90k. Analysis case SCB shows the maximum possible benefit of the filtering of the fission products in the containment (all non-isolation releases) to be $45k. The combined benefit is $135k. Not cost-beneficial; cost is expected to exceed twice the benefit.
36	Install an unfiltered hardened containment vent	Provides an alternate decay heat removal method (non-ATWS), which is not filtered	4.9%	1.6%	$90k	>2 x benefit	Screen out	Analysis case DHR determined the maximum benefit to be less than $90k. Not cost-beneficial; cost is expected to exceed twice the benefit.
37	Create/enhanc e hydrogen ignitors with independent power supply.	Use either a new, independent power supply, a non-safety grade portable generator, existing station batteries, or existing AC/DC independent power supplies such as the security system diesel. Would reduce hydrogen detonation at lower cost.	0.00%	0.02%	$1k	>2 x benefit	Screen out	Analysis case HYD determined the maximum benefit of eliminating containment failure due to hydrogen burns to be less than $1k. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
38	Create a passive hydrogen ignition system	Reduce hydrogen detonation potential without requiring electric power	0.00%	0.02%	$1k	>2 x benefit	Screen out	Analysis case HYD determined the maximum benefit of eliminating containment failure due to hydrogen burns to be less than $1k. Not cost-beneficial; cost is expected to exceed twice the benefit.
39	Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris	A molten core escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a meltthrough.	0.00%	100%	$1.64 million	>2 x benefit	Screen out	The baseline analysis shows a maximum possible benefit of removing all offsite releases to be $1.64 million. It is judged that this SAMA would likely have a cost an order of magnitude larger than this possible benefit. Not cost-beneficial; cost is expected to exceed twice the benefit.
40	Create a water cooled rubble bed on the pedestal	This rubble bed would contain a molten core dropping onto the pedestal, and would allow the debris to be cooled.	0.00%	100%	$1.64 million	>2 x benefit	Screen out	The baseline analysis shows a maximum possible benefit of removing all offsite releases to be $1.64 million. It is judged that this SAMA would likely have a cost and order of magnitude larger than this possible benefit. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
42	Enhance fire protection system and/or standby gas treatment system hardware and procedures	Improve fission product scrubbing in severe accidents	0.00%	4.9%	$45k	>2 x benefit	Screen out	Analysis case SCB shows the maximum possible benefit of the filtering of the fission products in the containment to be $44,800. It is judged that this SAMA would be at a greater cost than this benefit when all necessary hardware and procedural changes are included. Not cost-beneficial; cost is expected to exceed twice the benefit.
43	Create a reactor cavity flooding system	Would enhance debris coolability, reduce core concrete interaction and provide fission product scrubbing	0.00%	0.00%	$0	>2 x benefit	Screen out	Analysis case DEB found no benefit in the SPS level 2 analysis for flooding the reactor cavity. Not cost-beneficial; cost is expected to exceed twice the benefit.
44	Creating other options for reactor cavity flooding	Flood cavity via systems such as diesel driven fire pumps	0.00%	0.00%	$0	>2 x benefit	Screen out	Analysis case DEB found no benefit in the SPS level 2 analysis for flooding the reactor cavity. Not cost-beneficial; cost is expected to exceed twice the benefit.
46	Provide a core debris control system	Would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and containment shell.	0.00%	0.00%	$0	>2 x benefit	Screen out	This failure mode was not found to be a concern in the SPS Level 2 analysis, so it is judged to have a negligible benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
47	Create a core melt source reduction system (COMSORS)	Place enough glass underneath the reactor vessel such that a molten core falling on the glass would melt and combine with the material. Subsequent spreading and heat removal from the vitrified compound would be facilitated, and concrete attack would not occur (such benefits are theorized in the reference).	0.00%	100%	$1.64 million	>2 x benefit	Screen out	The baseline analysis shows a maximum possible benefit of removing all offsite releases to be $1.64 million. It is judged that this SAMA would likely have a cost and order of magnitude larger than this possible benefit. Not cost-beneficial; cost is expected to exceed twice the benefit.
48	Provide containment inerting capability	Would prevent combustion of hydrogen and carbon monoxide gases	0.00%	0.02%	$1k	>2 x benefit	Screen out	Analysis case HYD determined the maximum benefit of eliminating containment failure due to hydrogen burns to be less than $1k. Not cost-beneficial; cost is expected to exceed twice the benefit.
49	Use fire water spray pump for containment spray	Redundant containment spray method without high cost	0.00%	0.00%	$0	>2 x benefit	Screen out	Analysis case CSP shows a no benefit from this SAMA.
50	Install a passive containment spray system	Containment spray benefits at a very high reliability, and without support systems	0.00%	0.00%	$0	>2 x benefit	Screen out	Analysis case CSP shows a no benefit from this SAMA.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
54	Provide a reactor vessel exterior cooling system.	Potential to cool a molten core before it causes vessel failure, if the lower head can be submerged in water.	0.00%	4.9%	$45k	>2 x benefit	Screen out	Analysis case SCB shows the maximum possible benefit of the filtering of the fission products in the containment to be $44,800. This is judged to also be applicable to preventing a molten core from escaping into containment Not cost-beneficial; cost is expected to exceed twice the benefit.
55	Create another building, maintained at a vacuum to be connected to containment	In an accident, connecting the new building to containment would depressurize containment and reduce any fission product release.	0.00%	100%	$1.64 million	>2 x benefit	Screen out	The baseline analysis shows a maximum possible benefit of removing all offsite releases to be $1.64 million. It is judged that this SAMA would likely have a cost and order of magnitude larger than this possible benefit. Not cost-beneficial; cost is expected to exceed twice the benefit.
61	Use fuel cells instead of lead-acid batteries	Extend DC power availability in a SBO	5.4%	0.8%	$88k	>2 x benefit	Screen out	The System 80+ submittal (References 16 and 17) estimated the cost to be $2 million. The cost to an existing plant would be larger, while the maximum possible benefit calculated in analysis case BCH is only $88k, so this item is screened out. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
64	Alternate battery charging capability	Provide a portable diesel-driven battery charger.	5.4%	0.8%	$88k	>2 x benefit	Screen out	Analysis case BCH determined the maximum benefit of extended battery life during an accident to be $88k. The total battery load of the DC emergency buses during a four hour SBO event would require a 50KW battery charger. A portable unit with appropriate disconnects on the batteries for hook up during full power operation could be installed. The hookup would need to be brought out the alleyways where the diesel would be located when needed. Temporary cables would also be provided. Total cost for the diesel and plant modifications for its use $1.5-3M. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
69	Develop procedures to repair or change out failed 4KV breakers	Offers a recovery path from a failure of breakers that perform transfer of 4.16 kV non-emergency buses from unit station service transformers to system station service transformers, leading to loss of emergency AC power (i.e., in conjunction with failures of the diesel generators).	1.9%	2.0%	$62k	>2 x benefit	Screen out	The concept of capturing significant benefit through generation of a procedure is not realistic because the maintenance crews are already trained on the plant procedures for failed breakers. Therefore, the only portion of this SAMA given merit is the hardware portion (i.e., prestaged replacement breakers). Analysis case 4KV determined the maximum benefit to be $88k if half of all 4 KV breaker failures could be replaced in the timeframe considered in the PRA. The cost would be much greater than the actual benefit in order to have the many necessary breakers prestaged for this procedure to be effective. Not cost-beneficial; cost of purchasing, sheltering, and maintaining multiple prestaged 4KV breakers would exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
70	Emphasize steps in recovery of offsite power after a SBO.	Reduced human error probability of offsite power recovery.	1.8%	0.5%	$33k	>2 x benefit	Screen out	Analysis case OPR determined the maximum benefit to be less than $33k. The case was calculated using a 25% reduction in offsite power non-recovery terms. It is judged that this benefit is very optimistic given that training is already provided for offsite power recovery, and the fact that failure to recovery offsite power is likely to be governed by actual failures in the grid and not personnel failure. Not cost-beneficial; cost is expected to exceed twice the true obtainable benefit.
77	Provide a connection to alternate offsite power source (the Gravel Neck fossil units)	Increase offsite power redundancy	5.5%	1.5%	$105k	>2 x benefit	Screen out	Analysis case OSP determined the maximum benefit to be $105k. Assuming that the switchyard has been incapacitated, then a weather proof duct bank would need to be installed. The duct band would extend nearly ¾ of a mile and traverse under the Intake Canal for the plant. Switchgear would need to be provided at each end to disconnect from the normal sources and align the C/T to the Station buses. Total cost would be $2-5M. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
81	Alter electric power dependency to BC and CC SW valves	These valves require closing after a LOOP	0.7%	0.5%	$17k	>2 x benefit	Screen out	Analysis case BCC determined the maximum benefit to be $17k. The least expensive option would be to replace the BC and CC isolation valves with AOVs of a fail close design. Total cost to replace the operators, and install air lines, SOVs, etc would be $900K-1.5M. Not cost-beneficial; cost is expected to exceed twice the benefit.
82	Relocate transfer buses to different rooms	All of the transfer buses are located within the same room, which results in a high CDF fire sequence.	5.0%	0.7%	$41k	>2 x benefit	Screen out	Analysis case RTB determined the maximum benefit to be $41k. Not cost-beneficial; cost is expected to exceed twice the benefit.
83	Put a fast acting MG output breaker on both units	With a fast acting breaker, a turbine runback would be possible, reducing the likelihood of a reactor trip in some cases.	0.1%	0.04%	$3k	>2 x benefit	Screen out	Analysis case MGB determined the maximum benefit to be $3k. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
86	Improved SGTR coping abilities	Improved instrumentation to detect SGTR, or additional systems to scrub fission product releases.	2.8%	27%	$256k	>2 x benefit	Screen out	Analysis case SGI determined the maximum benefit to be 256k. This SAMA would involve the installation of numerous control circuits within the racks. Existing radiation alarms could be used to generate the high radiation signal. Close signals would be sent to the affected SG PORV, MSTV and Bypass valve, SG Blowdown Trip Valves and to the Terry Turbine steam supply valves (currently a manual valve but the valve would be changed to an AOV or MOV). Auto close to the auxiliary feedwater pumps would not be included to allow the operator time to assure that the SG had at least an 11% level before securing AFW. The mod would include the changeout of the Terry Turbine steam supply valves with control circuits to the racks and control room, instrumentation feeds from an existing rad monitor to the racks, appropriate annunciation in the control room to indicate the automatic action (including an automatic reactor trip) and wiring mods in the racks to the aforementioned components. Total cost would be $1.5-3M. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
88	Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift	SGTR sequences would not have a direct release pathway	5.7%	60%	$576k	>2 x benefit	Screen out	Analysis case SGR shows a maximum possible benefit of removing all SGTR to be $576k. It is judged that this SAMA would likely have a cost an order of magnitude larger than this possible benefit. Not cost-beneficial; cost is expected to exceed twice the benefit.
89	Replace steam generators with new design	Lower frequency of SGTR	5.7%	60%	$576k	>2 x benefit	Screen out	Analysis case SGR shows a maximum possible benefit of removing all SGTR to be $576k. It is judged that this SAMA would likely have a cost an order of magnitude larger than this possible benefit. Not cost-beneficial; cost is expected to exceed twice the benefit.
101	Ensure all ISLOCA releases are scrubbed	Would scrub ISLOCA releases. One suggestion was to plug drains in the break area so the break point would cover with water.	0.00%	5.3%	$40k	>2 x benefit	Screen out	Analysis case ISS shows a maximum possible benefit of this SAMA to be $40k. Assuming the break of concern is in the Safeguards building, a firewater line would be added to flood this area. The line would be remotely operated from the control room. The line would run from the main firewater header to a discharge point in the Safeguards building. The cost is estimated at $125k. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
103	Add a check valve downstream of the LHSI pumps on the cold leg injection line.	The ISLOCA frequency is dominated by the LHSI injection lines to the cold legs, which have 2 check valves each. Adding another check valve in the common injection line would essentially eliminate the frequency of the ISLOCA sequence through these pathways. However, a single check valve in the common line would create a single failure point for the system. Either a redundant line would have to be added with a check valve in each, or add a check valve to each of the 3 cold leg injection paths.	4.3%	30%	$253k	>2 x benefit	Screen out	Analysis case ISL shows a maximum possible benefit of removing all ISLOCA to be $253k. 3 check valves per unit can be added inside containment. There is an enduring cost associated with testing these check valves. Current testing is critical path, expensive and dose intensive. Present value cost of installing the mods and performing the future testing is $750K-1.25M. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
111	Install accumulators for turbine driven AFW pump flow control valves	Provide control air accumulators for the turbine driven AFW flow control valves, the motor driven AFW pressure control valves, and S/G PORVs. This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOP.	0.1%	0.04%	$4k	>2 x benefit	Screen out	Analysis case FWS shows the maximum possible benefit to be $4k. Not cost-beneficial; cost is expected to exceed twice the benefit.
115	Provide portable generators to be hooked in to the turbine driven AFW, after battery depletion	Extend AFW availability in a SBO (assuming the turbine-driven AFW requires DC power)	0.1%	0.04%	$4k	>2 x benefit	Screen out	Analysis case FWS shows the maximum possible benefit to be $4k. Not cost-beneficial; cost is expected to exceed twice the benefit.
122	Create passive secondary side coolers	Provide a passive heat removal loop with a condenser and heat sink. Would reduce CDF from the loss of feedwater.	12.8%	17.2%	$490k	>2 x benefit	Screen out	Analysis case FDW shows the maximum possible benefit as $490k. It is judged that this SAMA would likely be an order of magnitude greater than this benefit. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
123	Automate air bottle swap for S/G PORVs	Manual action is required to swap air source to the air bottles. Automatic swap on low pressure would eliminate the operator action.	0.00%	0.03%	<$1k	>2 x benefit	Screen out	Analysis case SGP shows the maximum possible benefit to be less than $1k. Not cost-beneficial; cost is expected to exceed twice the benefit.
124	Condenser dump after SI	Utilize bypass around the main steam trip valves to use the condenser dump after an SI (the PRA assumes the function can not be recovered after an SI signal)	2.2%	0.01%	$33k	>2 x benefit	Screen out	Analysis case CND shows the maximum possible benefit to be $33k. Not cost-beneficial; cost is expected to exceed twice the benefit.
125	Provide capability for diesel driven, low pressure vessel makeup	Extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., firewater)	5.0%	0.01%	$76k	>2 x benefit	Screen out	Analysis case LHI shows the benefit to be $76k. The total cost would include adding a line from the firewater header, a post indicator valve in the yard and SR double isolation valves to the connection with the LHSI system. Total cost would be $350-600K. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
126/127	Provide an additional high pressure injection pump with independent diesel	Reduce frequency of core melt from small LOCA sequences, and from SBO sequences.	3.5%	2.1%	$89k	>2 x benefit	Screen out	Analysis case HPI shows the maximum possible benefit to be $89k. Not cost-beneficial; cost is expected to exceed twice the benefit.
145/146	Install MG set trip breakers in control room	Provides trip breakers for the motor generator sets in the control room. Currently, at Watts Bar, an ATWS would require an immediate action outside the control room to trip the MG sets. Would reduce ATWS CDF	0.01%	0.00%	<1k	>2 x benefit	Screen out	Analysis case ATW shows the maximum possible benefit to be less than $1k. Not cost-beneficial; cost is expected to exceed twice the benefit.
154	Create/enhance reactor coolant system depressurization ability	Either with a new depressurization system, or with existing PORVs, head vents and secondary side valve, RCS depressurization would allow low pressure ECCS injection. Even if core damage occurs, low RCS pressure alleviates some concerns about high pressure melt ejection.	0.00%	0.00%	$0	>2 x benefit	Screen out	The SPS Level 2 analysis shows that high pressure melt ejection is not a threat to containment failure. SPS procedures already direct depressurization in the appropriate Level 1 sequences. Analysis case DEB shows that there is no benefit in the Level 2 analysis for low pressure injection after core damage. Therefore, revision to existing procedures or creation of a new system would not be expected to provide any benefit.

Table G.2-2 (continued)
Summary of SPS SAMAs Considered in Cost-Benefit Analysis

SAMA No.	Potential Improvement	Discussion	Reduction in CDF (bounding)	Reduction in Person-Rem Offsite (bounding)	Benefit (bounding)	Estimated Cost	Conclusion	Cost Estimate And Basis For Conclusion
158	Secondary side guard pipes up to the MSIVs.	Would prevent secondary side depressurization should a steam line break occur upstream of the MSIVs. Would also guard against or prevent consequential multiple SGTR following a main steam line break event.	0.00%	0.00%	$0	>2 x benefit	Screen out	Analysis case SLB shows there is an inconsequential benefit for MSLB SAMAs, so this item is screened out. Not cost-beneficial; cost is expected to exceed twice the benefit.
159	Digital large break LOCA protection	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (a leak before break).	3.3%	0.01%	$25k	>2 x benefit	Screen out	Analysis case LLO shows a benefit of $25k for this SAMA, which assumed a reduction in large LOCA frequency of 25%. It is judged that the cost of such instrumentation would be many times greater than $25k to be able to achieve this benefit. Not cost-beneficial; cost is expected to exceed twice the benefit.

Table G.2-3
Sensitivity Analysis Results

SAMA Number	Potential Improvement	Baseline	Case 1 (3% DR)	Case 2 (15% DR)	Case 3 (95% Evac)	Case 4 (1997 Met)	Case 5 (1996 Met)	Case 6 (+10% ST PLHEAT)	Case 7 (-50% ST PLHEAT)	Case 8 (+50% Timing)	Case 9 (-50% Timing)	Case 10 (DLTSHL = 5400)	Case 11 (CDFRM & CDNFRM x 1.46)
9	Provide additional SW pump	$34k	$58k	$22k	$34k	$34k	$34k	$34k	$34k	$34k	$34k	$34k	$34k
10	Create an independent RCP seal injection system, with dedicated diesel	$63k	$112k	$42k	$64k	$64k	$63k	$64k	$63k	$63k	$63k	$63k	$64k
11	Create an independent RCP seal injection system, without dedicated diesel	$63k	$112k	$42k	$64k	$64k	$63k	$64k	$63k	$63k	$63k	$63k	$64k
14	Install improved RCP seals	$63k	$112k	$42k	$64k	$64k	$63k	$64k	$63k	$63k	$63k	$63k	$64k
15	Add a third CCW pump	$5k	$8k	$3k	$5k	$5k	$5k	$5k	$5k	$6k	$5k	$5k	$6k
21	Loss of CCW or SW procedural enhancements	$5k	$8k	$3k	$5k	$5k	$5k	$5k	$5k	$6k	$5k	$5k	$6k
23	Alter circ water valve power supply arrangement	-$4k	-$7k	-$2k	-$4k	-$4k	-$4k	-$4k	-$4k	-$4k	-$4k	-$4k	-$4k
25	Provide a non-safety related, redundant train of switchgear ventilation	$278k	$470k	$178k	$278k	$282k	$284k	$278k	$280k	$282k	$274k	$280k	$281k

Table G.2-3 (continued)
Sensitivity Analysis Results

SAMA Number	Potential Improvement	Baseline	Case 1 (3% DR)	Case 2 (15% DR)	Case 3 (95% Evac)	Case 4 (1997 Met)	Case 5 (1996 Met)	Case 6 (+10% ST PLHEAT)	Case 7 (-50% ST PLHEAT)	Case 8 (+50% Timing)	Case 9 (-50% Timing)	Case 10 (DLTSHL = 5400)	Case 11 (CDFRM & CDNFRM x 1.46)
27	Add a switchgear room high temp alarm	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k
30	Install containment spray throttle valves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Develop an enhanced containment spray system	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33	Provide a dedicated existing containment spray system	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Install a containment vent large enough to remove ATWS decay heat	$90k	$154k	$58k	$90k	$91k	$90k	$90k	$90k	$90k	$90k	$90k	$91k
35	Install a filtered containment vent to remove decay heat	$135k	$207k	$85k	$133k	$141k	$151k	$136k	$136k	$136k	$136k	$136k	$137k
36	Install an unfiltered hardened containment vent	$90k	$154k	$58k	$90k	$91k	$90k	$90k	$90k	$90k	$90k	$90k	$91k
37	Create/enhance hydrogen ignitors with independent power supply.	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k

Table G.2-3 (continued)
Sensitivity Analysis Results

SAMA Number	Potential Improvement	Baseline	Case 1 (3% DR)	Case 2 (15% DR)	Case 3 (95% Evac)	Case 4 (1997 Met)	Case 5 (1996 Met)	Case 6 (+10% ST PLHEAT)	Case 7 (-50% ST PLHEAT)	Case 8 (+50% Timing)	Case 9 (-50% Timing)	Case 10 (DLTSHL = 5400)	Case 11 (CDFRM & CDNFRM x 1.46)
38	Create a passive hydrogen ignition system	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k
39	Create a giant concrete crucible with heat removal potential under the basemat to contain molten debris	$1.6 million	$2.3 million	$960k	$1.7 million	$1.7 million	$1.6 million	$1.7 million	$1.7 million	$1.8 million	$1.6 million	$1.7 million	$1.8 million
40	Create a water cooled rubble bed on the pedestal	$1.6 million	$2.3 million	$960k	$1.7 million	$1.7 million	$1.6 million	$1.7 million	$1.7 million	$1.8 million	$1.6 million	$1.7 million	$1.8 million
42	Enhance fire protection system and/or standby gas treatment system hardware and procedures	$45k	$63k	$27k	$44k	$50k	$61k	$46k	$46k	$46k	$46k	$46k	$46k
43	Create a reactor cavity flooding system	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	Creating other options for reactor cavity flooding	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
46	Provide a core debris control system	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table G.2-3 (continued)
Sensitivity Analysis Results

SAMA Number	Potential Improvement	Baseline	Case 1 (3% DR)	Case 2 (15% DR)	Case 3 (95% Evac)	Case 4 (1997 Met)	Case 5 (1996 Met)	Case 6 (+10% ST PLHEAT)	Case 7 (-50% ST PLHEAT)	Case 8 (+50% Timing)	Case 9 (-50% Timing)	Case 10 (DLTSHL = 5400)	Case 11 (CDFRM & CDNFRM x 1.46)
47	Create a core melt source reduction system (COMSORS)	$1.6 million	$2.3 million	$960k	$1.7 million	$1.7 million	$1.6 million	$1.7 million	$1.7 million	$1.8 million	$1.6 million	$1.7 million	$1.8 million
48	Provide containment inerting capability	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k	$1k
49	Use fire water spray pump for containment spray	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
50	Install a passive containment spray system	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
54	Provide a reactor vessel exterior cooling system.	$45k	$63k	$27k	$44k	$50k	$61k	$46k	$46k	$46k	$46k	$46k	$46k
55	Create another building, maintained at a vacuum to be connected to containment	$1.6 million	$2.3 million	$960k	$1.7 million	$1.7 million	$1.6 million	$1.7 million	$1.7 million	$1.8 million	$1.6 million	$1.7 million	$1.8 million
61	Use fuel cells instead of lead-acid batteries	$88k	$154k	$58k	$88k	$89k	$92k	$88k	$88k	$88k	$88k	$88k	$88k
64	Alternate battery charging capability	$88k	$154k	$58k	$88k	$89k	$92k	$88k	$88k	$88k	$88k	$88k	$88k

Table G.2-3 (continued)
Sensitivity Analysis Results

SAMA Number	Potential Improvement	Baseline	Case 1 (3% DR)	Case 2 (15% DR)	Case 3 (95% Evac)	Case 4 (1997 Met)	Case 5 (1996 Met)	Case 6 (+10% ST PLHEAT)	Case 7 (-50% ST PLHEAT)	Case 8 (+50% Timing)	Case 9 (-50% Timing)	Case 10 (DLTSHL = 5400)	Case 11 (CDFRM & CDNFRM x 1.46)
69	Develop procedures to repair or change out failed 4KV breakers	$62k	$96k	$38k	$62k	$62k	$60k	$62k	$62k	$64k	$58k	$62k	$63k
70	Emphasize steps in recovery of offsite power after a SBO.	$33k	$57k	$22k	$34k	$34k	$34k	$34k	$34k	$34k	$34k	$34k	$34k
77	Provide a connection to alternate offsite power source (the Gravel Neck fossil units)	$105k	$180k	$68k	$106k	$106k	$106k	$106k	$106k	$106k	$104k	$106k	$106k
81	Alter electric power dependency to BC and CC SW valves	$17k	$27k	$11k	$17k	$17k	$17k	$17k	$17k	$17k	$17k	$17k	$17k
82	Relocate transfer buses to different rooms	$41k	$72k	$27k	$41k	$42k	$43k	$41k	$41k	$41k	$41k	$41k	$41k
83	Put a fast acting MG output breaker on both units	$3k	$4k	$2k	$3k	$3k	$3k	$3k	$3k	$3k	$3k	$3k	$3k
86	Improved SGTR coping abilities	$256k	$366k	$152k	$263k	$262k	$239k	$260k	$262k	$277k	$231k	$262k	$269k

Table G.2-3 (continued)
Sensitivity Analysis Results

SAMA Number	Potential Improvement	Baseline	Case 1 (3% DR)	Case 2 (15% DR)	Case 3 (95% Evac)	Case 4 (1997 Met)	Case 5 (1996 Met)	Case 6 (+10% ST PLHEAT)	Case 7 (-50% ST PLHEAT)	Case 8 (+50% Timing)	Case 9 (-50% Timing)	Case 10 (DLTSHL = 5400)	Case 11 (CDFRM & CDNFRM x 1.46)
88	Increase secondary side pressure capacity such that a SGTR would not cause the relief valves to lift	$576k	$821k	$342k	$590k	$590k	$537k	$584k	$588k	$624k	$518k	$588k	$605k
89	Replace steam generators with new design	$576k	$821k	$342k	$590k	$590k	$537k	$584k	$588k	$624k	$518k	$588k	$605k
101	Ensure all ISLOCA releases are scrubbed	$40k	$56k	$24k	$41k	$46k	$42k	$41k	$41k	$40k	$41k	$41k	$44k
103	Add a check valve downstream of the LHSI pumps on the cold leg injection line.	$253k	$366k	$151k	$259k	$284k	$261k	$259k	$258k	$264k	$260k	$259k	$269k
111	Install accumulators for turbine driven AFW pump flow control valves	$4k	$4k	$2k	$4k	$4k	$4k	$4k	$4k	$4k	$4k	$4k	$4k
115	Provide portable generators to be hooked in to the turbine driven AFW, after battery depletion	$4k	$4k	$2k	$4k	$4k	$4k	$4k	$4k	$4k	$4k	$4k	$4k

Table G.2-3 (continued)
Sensitivity Analysis Results

SAMA Number	Potential Improvement	Baseline	Case 1 (3% DR)	Case 2 (15% DR)	Case 3 (95% Evac)	Case 4 (1997 Met)	Case 5 (1996 Met)	Case 6 (+10% ST PLHEAT)	Case 7 (-50% ST PLHEAT)	Case 8 (+50% Timing)	Case 9 (-50% Timing)	Case 10 (DLTSHL = 5400)	Case 11 (CDFRM & CDNFRM x 1.46)
122	Create passive secondary side coolers	$490k	$762k	$302k	$498k	$500k	$472k	$496k	$498k	$518k	$460k	$498k	$507k
123	Automate air bottle swap for S/G PORVs	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k	<$1k
124	Condenser dump after SI	$33k	$59k	$22k	$33k	$33k	$33k	$33k	$33k	$33k	$34k	$34k	$34k
125	Provide capability for diesel driven, low pressure vessel makeup	$76k	$136k	$50k	$76k	$76k	$76k	$76k	$76k	$76k	$76k	$76k	$76k
126/127	Provide an additional high pressure injection pump with independent diesel	$89k	$146k	$56k	$90k	$90k	$88k	$90k	$90k	$92k	$86k	$90k	$91k
145/146	Install MG set trip breakers in control room	<1k	<1k	<1k	<1k	<1k	<1k	<1k	<1k	<1k	<1k	<1k	<1k
154	Create/enhance reactor coolant system depressurization ability	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
158	Secondary side guard pipes up to the MSIVs.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Table G.2-3 (continued)
Sensitivity Analysis Results

SAMA Number	Potential Improvement	Baseline	Case 1 (3% DR)	Case 2 (15% DR)	Case 3 (95% Evac)	Case 4 (1997 Met)	Case 5 (1996 Met)	Case 6 (+10% ST PLHEAT)	Case 7 (-50% ST PLHEAT)	Case 8 (+50% Timing)	Case 9 (-50% Timing)	Case 10 (DLTSHL = 5400)	Case 11 (CDFRM & CDNFRM x 1.46)
159	Digital large break LOCA protection	$25k	$45k	$17k	$25k	$25k	$25k	$25k	$25k	$25k	$25k	$25k	$25k

G.2.5 References

Ref. G.2-1 "Surry Power Station IPE," Virginia Electric And Power Company, August 1991.

Ref. G.2-2 Letter from Mr. M. O. Medford (TVA) to NRC Document Control Desk, dated September 1, 1992. "Watts Bar Nuclear Plant (WBN) Units 1 and 2 – Generic Letter (GL) 88-20 – Individual Plant Examination (IPE) for Severe Accident Vulnerabilities – Response – (TAC M74488)."

Ref. G.2-3 "Cost Estimate for Severe Accident Mitigation Design Alternatives. Limerick Generating Station for Philadelphia Electric Company," Bechtel Power Corporation, June 22, 1989.

Ref. G.2-4 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Volume 1, Table 5.35, Listing of SAMDAs considered for the Limerick Generating Station, NRC, May 1996.

Ref. G.2-5 NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Volume 1, Table 5.36, Listing of SAMDAs considered for the Comanche Peak Steam Electric Station, NRC, May 1996.

Ref. G.2-6 Letter from Mr. W. J. Museler (TVA) to NRC Document Control Desk, dated June 5, 1993. "Watts Bar Nuclear Plant (WBN) Units 1 and 2 – Severe Accident Mitigation Design Alternatives (SAMDA) - (TAC Nos. M77222 and M77223)."

Ref. G.2-7 Letter from Mr. D. E. Nunn (TVA) to NRC Document Control Desk, dated October 7, 1994. "Watts Bar Nuclear Plant (WBN) Units 1 and 2 – Severe Accident Mitigation Design Alternatives (SAMDA) – Response to Request for Additional Information (RAI) - (TAC Nos. M77222 and M77223)."

Ref. G.2-8 Letter from N. J. Liparulo (Westinghouse Electric Corporation) to NRC Document Control Desk, dated December 15, 1992, "Submittal of Material Pertinent to the AP600 Design Certification Review."

Ref. G.2-9 Brookhaven National Laboratory, Department of Advanced Technology, Technical Report FIN W-6449, "NRC – IPE Workshop Summary/ Held in Austin Texas; April 7-9 1997," dated July 17, 1997/Appendix F – Industry Presentation Material, Contribution by Swedish Nuclear Power Inspectorate (SKI) and Safety Assessment Consulting (SAC): "Insights from PSAs for European Nuclear Power Plants," presented by Wolfgang Werner, SAC.

Ref. G.2-10 Brookhaven National Laboratory, Department of Advanced Technology, Technical Report FIN W-6449, "NRC – IPE Workshop Summary/ Held in Austin

Texas; April 7-9 1997," dated July 17, 1997/Appendix D – NRC Presentation Material on Draft NUREG-1560.

Ref. G.2-11 NUREG 0498, "Final Environmental Statement related to the operation of Watts Bar Nuclear Plant, Units 1 and 2," Supplement No. 1, NRC, April 1995.

Ref. G.2-12 NUREG/CR-5567, "PWR Dry Containment Issue Characterization," NRC, August 1990.

Ref. G.2-13 NUREG-1560, ""Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," Volume 2, NRC, December 1997.

Ref. G.2-14 NUREG/CR-5630, "PWR Dry Containment Parametric Studies," NRC, April 1991.

Ref. G.2-15 NUREG/CR-5575, "Quantitative Analysis of Potential Performance Improvements for the Dry PWR Containment," NRC, August 1990.

Ref. G.2-16 CESSAR Design Certification, Appendix U, Section 19.15.5, Use of PRA in the Design Process, December 31, 1993.

Ref. G.2-17 NUREG 1462, "Final Safety Evaluation Report Related to the Certification of the System 80+ Design," NRC, August 1994.

Ref. G.2-18 Forsberg, C. W., E. C., Beahm, and G. W. Parker, "Core-Melt Source Reduction System (COMSORS) to Terminate LWR Core-Melt Accidents," Second International Conference on Nuclear Engineering (ICONE-2) San Francisco, California, March 21-24, 1993.

Ref. G.2-19 "Individual Plant Examination Of Non-Seismic External Events And Fires - Surry Power Station Units 1 And 2," Virginia Electric And Power Company, December 1994.

Ref. G.2-20 "Regulatory Analysis Technical Evaluation Handbook", NUREG/BR-0184, January 1997.

Ref. G.2-21 PA-CALC, "Individual Plant Examination Long-Term Modifications," Surry Power Station Units 1 and 2, Type 2 NP 2584H, September 1, 1992.

G.3 RESULTS AND CONCLUSIONS

After all screening and cost-benefit analyses, there are no SAMAs considered to be cost-beneficial. The PRA calculations supporting this conclusion are recognized to have some uncertainty around the mean frequencies used in the analyses. To account for the possible uncertainty, several analyses were performed to bound the analysis. These sensitivity cases did not alter the benefit calculations by more than a factor of two, which were shown within the report to still outweigh the costs of each SAMA.